

UPDATED UNDERGROUND INJECTION CONTROL REGULATIONS

PUBLIC COMMENT SUMMARY AND RESPONSE

Public Comment Period:
July 27, 2018 – September 13, 2018

Public Comment Hearings:
Bakersfield – September 12, 2018
Los Angeles – September 13, 2018

INTRODUCTION

The following comments, objections, and recommendations were made regarding the proposed Updated Underground Injection Control Regulations rulemaking action during a public comment period beginning July 27, 2018 and ending September 13, 2018. During that public comment period, two public comment hearings were conducted, one in Bakersfield on September 12, and one in Los Angeles on September 13.

Over the course of the public comment period, the Division received a number of public comments via email, regular mail, public comment hearing, and fax. These comments ranged from detailed comments on the proposed requirements to general concerns about groundwater protection.

To facilitate the process of reviewing and responding to comments, the Division assigned a unique numerical signifier to each comment. This signifier consists of three components: first, a unique code number assigned to each commenter; second, a separating hyphen; third, a sequential number assigned to each comment from the identified commenter. The chart below lists the code number for each commenter. Within this document, you will find either grouped or individual numerical signifiers, followed by a summary or specific comment, followed by a response (italicized).

COMMENTERS

Number	Name and/or Entity
0001	BE Conway Energy
0002	California Independent Petroleum Association (CIPA)
0003	Signal Hill Petroleum
0004	E&B Natural Resources
0005	State Building and Construction Trades Council of California
0006	Environmental Defense Fund
0007	Macpherson Oil Company
0008	Natural Resources Defense Council (NRDC)
0009	Pacific Coast Energy Company

0010	Sentinel Peak Resources
0011	Pacific Gas & Electric Company
0012	Chevron
0013	Center for Biological Diversity
0014	Western States Petroleum Association (WSPA)
0015	Central Valley Gas Storage; Gill Ranch Storage; Lodi Gas Storage, LLC; Wild Goose Storage, LLC
0016	Southern California Gas Company
0017	California Resources Corporation
0018	Preston Jordan
0019	Clean Water Action

ACRONYMS

AE	Aquifer Exemption
AOR	Area of Review
API	American Petroleum Institute
CASRN	Chemical Abstracts Service Registry Number
CFR	Code of Federal Regulations
CCR	California Code of Regulations
Division	Department of Conservation, Division of Oil, Gas, and Geothermal
DOGGR	Department of Conservation, Division of Oil, Gas, and Geothermal
EOR	Enhanced Oil Recovery
Legislature	Legislature of the State of California
OES	California Governor's Office of Emergency Services
OSHA	Occupational Safety and Health Administration
MASP	Maximum Allowable Surface Pressure
MOA	Memorandum of Agreement
MIT	Mechanical Integrity Testing
NTO	Notice to Operators
PAL	Project Approval Letter
PRC	Public Resources Code
SB 4	Senate Bill 4 (2013-2014)
SB 1281	Senate Bill 1281 (2013-2014)
SCADA	Supervisory Control and Data Acquisition
SDWA	Safe Drinking Water Act (Federal)
SRIA	Standardized Regulatory Impact Assessment
SWRCB	State Water Resources Control Board
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
US EPA	United States Environmental Protection Agency

GENERAL COMMENTS

Comments in Support

0004-1 1724.10.1: Water injection – the proposed testing is acceptable.
0004-4 1724.10.2: Water injection – the proposed testing is acceptable
0004-6 1724.10.2: For sandstone reservoir continuous steam – proposed regulation testing is acceptable. Radioactive tracers can be run every two years.
0008-28 1724.7, 1724.10(a), (b), (j), (l), 1724.10.1(a), and 1724.7.3 (a)(1) and (a)(2): Commenter generally supports the proposed revisions and additions to these subsections.
0019-15 1724.6(e): Commenter supports this section and DOGGR’s authority to require immediate cessation of injection.
0019-12 1724.6: Commenter supports the flexibility on timing for approval of injection projects and would oppose any time limits for the Division or any other agency involved in oversight, to review permit applications or other documents.
<i>Response to Comment 0004-1, 0004-4, 0004-6, 0008-28, 00019-15, 0019-12: ACCEPTED. Thank you for your participation in the public comment process.</i>

General Opposition

0002-1, 0008-1 Overall, we are concerned that the proposed regulations largely treat all injection operations the same. Injection activities occurring in California include water and waste gas disposal and Enhanced Oil Recovery (EOR) operations such as waterflooding, steam flooding, and cyclic steam. Carbon dioxide EOR has also been proposed as a recovery method in the state. For example, disposal projects inject fluids for permanent storage without withdrawing fluids, which may increase the formation pressure over time whereas in EOR projects like waterflooding and steam flooding, both injection and withdrawal is occurring from the same formation, which may help balance pressure. Cyclic steam projects use the same wells to both inject and withdraw fluids, whereas disposal and waterflood or steam flood projects are more likely to use dedicated injectors. These operational differences present different threats to the environment and human health and safety and should be better reflected in the Division’s regulations. The unique challenges and threats associated with different types of injection must be explicitly addressed in regulation to ensure transparent and consistent application of best available standards to protect the environment, health, and safety.
0014-20 The one-size-fits-all approach of the draft regulations does not recognize some of the major distinctions in oil and gas production in the State, or distinctions between the different types of activity that occur under the UIC program. For example, the draft regulations fail to distinguish between water and steam injection, continual and cyclic injection, and cyclic injection that augment

production wells in steamflood projects as opposed to cyclic injection in low permeability shallow diatomite formations. It does not make sense to treat cyclic injection in production wells in the same manner as continuous steam/water injectors. In addition to more closely defining the different types of cyclic operations and creating operationally-specific regulations that are justified based on their operational attributes, the regulations would also be greatly improved if they were amended to provide distinction in requirements between injection occurring outside of hydrocarbon-bearing strata and injection occurring within hydrocarbon-bearing strata. This is a fundamental distinction that has a direct bearing on the physical risk of the injection.

Response to Comments 0002-1 0008-1, 0014-20: ACCEPTED IN PART. The proposed regulations do not follow a “one size fits all” approach. Many provisions of the regulatory text vary by well type, as appropriate to accommodate the different needs and capacities of different uses and configurations. For example, the requirement for tubing and packer is dependent on well type, mechanical integrity testing frequency is based on well type, and test procedures for radioactive tracer surveys recognize the differences between well types. In addition, the First Revised Text of Proposed Regulations includes a newly created category of low-use cyclic steam injection wells, intended to facilitate closer tailoring of applicable requirements to specific well characteristics. Geologic and operational concerns specific to a localized area or to an individual underground injection project are more appropriately addressed within the terms and conditions of a project approval letter (PAL) rather than a statewide regulation. Proposed section 1724.6 establishes a regulatory framework explicitly contemplating the use of PALs for this purpose.

0007-26

The term Life, Health, Property and Natural Resources is used in the proposed regulations. These items are important and should be used as part of DOGGR’s tasking in its entirety. If used the term should include a synopsis of DOGGR’s overall tasking to ensure the wise development production of oil and gas through good conservation and engineering practices. Recommend that the term if used by “Encourages the wise development of oil and gas resources through good conservation and engineering practices that protects life, health, property, and natural resources. This statement is reflective of DOGGR’s overall mission and duties is more consistent with the legislation that established and DOGGR’s PR11 document.

Response to Comment 0007-26: NOT ACCEPTED. The addition of the suggested language would not have a practical impact on the proposed regulations. The reference to “life, health, property, and natural resources” sets a standard for the types of harm that must be prevented. The term “natural resources” includes the hydrocarbon resources to be wisely developed, as referenced in the PRC. While the regulation emphasizes the provisions in PRC section 3106, subdivision (a), the referenced language from PRC section 3106, subdivision (d) remains a statutory mandate on the Division. The Division believes that protecting life health, property, and natural resources is inherent in any policy associated with the “wise development of oil and gas resources.”

0013-8

In 2015, DOGGR released a self-audit that stated that there was an immediate need for new regulations and procedures regarding well construction, zone of endangerment analyses, inspections, remediation, data management, and other requirements to ensure minimal protection from dangerous well production activities. Unfortunately, these proposed regulations fall short of

addressing these shortcomings and providing greater protections for the environment. Not only are the proposed regulations dangerous, they are also inconsistent with the federal law regulations governing underground injection of fluids. Section 1421(b) of the SDWA demands that regulations for state UIC Programs require applicants for an injection permit to “satisfy the State that the underground injection will not endanger drinking water sources.” Injection above the fracture gradient increases the risk that drinking water sources will be contaminated. Allowing drinking water sources to be endangered by allowing injection above fracture gradient puts the state in violation of its obligations under the SDWA. Moreover, Section 1425 of the SDWA does not prohibit a state from enacting regulations that are more stringent than those set out in the SDWA. DOGGR should protect underground water in a manner that adequately takes into account current and future water crises in California. Doing so requires protection of water certainly with more than 3,000 mg/L TDS, and even more than 10,000 mg/L TDS.

***Response to Comment 0013-8: NOT ACCEPTED.** The assertion in this comment that the proposed regulations are not consistent with the SDWA is incorrect. PRC section 3106, subdivision (b), directs the Division to “supervise the drilling, operation, maintenance, and abandonment of wells so as to permit the owners or operators of the wells to utilize all methods and practices known to the oil industry for the purpose of increasing the ultimate recovery of underground hydrocarbons....” At the same time, the Division has a broad mandate to protect life, health, property, and natural resources. Properly interpreted, the legislative direction of PRC section 3106 contemplates that, where a practice can be permitted with manageable risk, it may be permitted. The proposed regulations are consistent with this legislative direction. The Division carefully scrutinizes operators’ proposed injection projects. The proposed regulations only allow for injection above fracture gradient where it can be done safely, without fluid migration harmful to groundwater resources, as determined based on the relevant geology and operational practices. Additionally, the SWRCB reviews each UIC project and may choose to impose conditions on approved operations as appropriate to protect groundwater and other resources. The US EPA oversees nationwide implementation of the SDWA. The Division conferred with the US EPA on a regular basis regarding development of the proposed regulations. The proposed regulations impose some of the most stringent UIC review and testing requirements in the nation. The proposed regulations are consistent with the objectives of the SDWA.*

0013-6

These revisions would substantially change the regulatory requirements that were presented to the U.S. EPA when California applied for primary authority (“primacy”) over Class II injection wells. Such substantial changes to groundwater protection in the state would have to be first approved by the EPA before DOGGR could implement these rules. The regulations would not be enforceable until the EPA has formally approved the changes. Given the potential environmental impacts that would occur as a result of these changes, EPA would be required to conduct and complete a full environmental impact study (EIS) prior to approving these.

***Response to Comment 0013-6: NOT ACCEPTED.** This comment misconstrues the relationship between the SDWA and the Division’s regulatory authority. The US EPA’s approval of a program revision is not a prerequisite for adoption of the proposed regulations as California law. The Division’s authority to regulate the drilling, operation, maintenance, and plugging and abandonment of oil and gas related injection wells within California resides in state law. (See PRC, §§ 3000 et seq., 3106.) The Informative*

Digest portion of the Notice of Proposed Rulemaking Action discusses the history of the SDWA and its interplay with state law.

The Division has communicated with the US EPA about the proposed regulations frequently throughout the development lifetime of the proposed regulations. It is likely that either the Division or the US EPA will initiate a program revision after the completion of this rulemaking action. A primary purpose of such a revision would be to update federal documentation for the Class II portion of the UIC program for California, so that it accounts for recent changes in applicable California law, including the proposed regulations. Procedures for revision of an existing UIC program exist in federal regulations. (See 40 CFR § 145.32.) Additional guidance regarding how the US EPA may interpret and apply these procedures may be found in US EPA UIC Guidance 34, available from the US EPA and on the Division's website.

0013-7

Commenter analyzes PRC 3106 and indicates that the duty to prevent harm supersedes the wise development of oil and gas such that DOGGR cannot encourage development of oil and gas if it is possible to prevent damage to life, health, property and natural resources by taking alternative actions. The proposed regulations cannot be reconciled with the duty to prevent harm under subdivision (a). Additionally, Article X of the California Constitution requires water resources to be put to "beneficial use to the fullest extent of which they are capable. The use of groundwater aquifers to dispose of oil field wastewater is a wasteful, unreasonable use of water. The State has a duty to prevent this destructive use of our aquifers, and to recalibrate and rebalance the groundwater system in light of recent and likely future droughts and other threats posed by climate change. Furthermore, a California Appellate Court recently affirmed that the public trust doctrine applies to the state's groundwater resources. The proposed regulations violate the public trust doctrine by failing to ensure that groundwater is adequately protected for the public. Control Board states in Resolution 68-16 that waters of the state must be protected "to promote the peace, health, safety, and welfare of the state." Water injection may not create pollution or a nuisance and must be "consistent with the maximum benefit of to the people of the state...." DOGGR must adhere to these legal protections by prohibiting injection activity that would create pollution or a nuisance.

Response to Comment 0013-7: NOT ACCEPTED. *This comment misconstrues the legislative direction provided in PRC 3106. PRC section 3106, subdivision (b), directs the Division to "supervise the drilling, operation, maintenance, and abandonment of wells so as to permit the owners or operators of the wells to utilize all methods and practices known to the oil industry for the purpose of increasing the ultimate recovery of underground hydrocarbons...." At the same time, the Division has a broad mandate to protect life, health, property, and natural resources. Properly interpreted, the legislative direction of PRC section 3106 contemplates that, where a practice can be permitted with manageable risk, it may be permitted. The proposed regulations are consistent with this legislative direction. The Division disagrees with the commenter's assertions that the proposed regulations are somehow in conflict with Article X of the California Constitution, the public trust doctrine, and SWRCB Resolution 68-16. In its capacity as a regulator of underground injection projects, the Division does consider, and will continue to consider, applicable state laws and policies. Additional to the Division's regulatory oversight, the SWRCB and the regional water boards also exercise their own independent regulatory*

authorities applicable to underground injection projects. To facilitate efficient and effective administration of applicable law and policy, the Division coordinates with the SWRCB and the regional water boards in the evaluation and approval of underground injection projects. For the same reasons, the Division consulted with the SWRCB and the regional water boards in the development of the proposed regulations. The proposed regulations will improve, not hinder, the Division's ability to achieve its regulatory mission as defined by state law and policy.

Alternative Methods of Compliance

0013-3

The standards for data collection in the proposed regulations are too vague. The Division should establish minimum standards for compliance rather than allowing undefined "alternative" methods of compliance. Section 1724.7(e) allows the division "discretion to make case-by-case determinations regarding the acceptance of alternative data." The proposed regulations state that the Division may do so when providing the data is infeasible and unreasonable for an operator. It is unclear when those situations would arise, nor what kind of alternative data would suffice. Similarly, section 1724.8(a)(3) gives the Division discretion to approve permits based on "alternative" showing that abandoned wells will not conduct fluid. It is unclear what basis the Division would accept or under what circumstances the cementing standard would not apply.

Response to Comment 0013-3: NOT ACCEPTED. *In each instance where an alternative showing may be allowed, the Division has set a clear performance standard to be met. As discussed in the Initial Statement of Reasons, these performance standards allow greater flexibility than a set of prescriptive criteria, as long as the identified regulatory objectives are achieved. Government Code section 11340.1 directs agencies to favor the use of regulatory performance standards rather than prescriptive criteria in situations where performance standards will be equally effective and less burdensome.*

Proposed section 1724.7, subdivision (a), adds language intended to preserve, within specified parameters, the Division's existing discretion to make case-by-case determinations regarding the acceptance of alternative data. While the data requirements of proposed section 1724.7 are intended to be appropriate for the vast majority of underground injection projects, the Division finds it necessary and appropriate to retain limited flexibility when evaluating the sufficiency of data submissions. Flexibility in the data requirements allows the Division to ensure it has whatever data is needed to evaluate a project, while ensuring that the project will be evaluated according to the appropriate standard for compliance rather than categorically denied solely on the basis of prescriptive data requirements. Subdivision (e) only allows for alternative project data in instances where it would be an unreasonable burden to provide the required data, and the Division is satisfied that the alternative data meets the performance standard and purposes of subdivision (a). Specifically, the performance standard requires the alternative data be sufficient to satisfy the Division that "the underground injection project is, on whole, supported by data demonstrating that the injected fluid will be confined to the approved injection zone" and otherwise conforms to all applicable laws.

Proposed section 1724.8, subdivision (a)(3), would allow the Division to approve injection operations based on an alternative demonstration that fluid will be confined to the approved injection zone notwithstanding the presence of abandoned wells that fail to meet the specifications set forth in proposed subdivision (a)(2). Specifically, the performance standard requires a demonstration that the well will not be a potential conduit for fluid migration outside the approved injection zone. The Initial Statement of Reasons provided an example of where this alternative demonstration performance standard may find application: if a plugged and abandoned well has only 90 feet of cement above the specified locations, there may nevertheless be project or site-specific grounds (i.e., geology and operational conditions) for finding that the well will not act as a conduit. Operators would carry the burden of making the demonstration, and the Division would make written findings explaining the basis for its concurrence with the demonstration.

Annual Inspection

0013-10

In 2011, the Horsley Witten Group, Inc. prepared a US EPA-commissioned report summarizing its audit of the Division's UIC program. That report included a recommendation that wells injecting near the maximum allowable surface pressure should be inspected annually. The proposed regulations are deficient because they do not contain such a requirement.

Response to Comment 0013-10: NOT ACCEPTED. *The Division allocates its staff resources to inspect wells and facilities based in part on risk assessment. The practical realities of fluctuating workloads may also affect staff availability. Under the proposed regulations, in combination with existing law, operators will be required to monitor, collect, and report to the Division a variety of data points that will facilitate robust regulatory supervision of operations without a predetermined schedule of obligatory site inspections. For example, proposed section 1724.10.4 requires operators to continuously record well-specific injection pressure data for all times that a well is approved for injection, and to maintain that data for at least three years after injection approval ends. This will enable the Division to initiate a data-rich, well-specific audit of injection pressure compliance at any time. The Division anticipates that many aspects of the proposed regulations—particularly the revisions to project data and testing requirements—will help the Division prioritize its resources more effectively. The ability to prioritize deployment of its resources in a flexible manner aids the Division in the service of its regulatory mission.*

Economic Analysis

0014-24

DOGGR must conduct a comprehensive economic analysis of the anticipated costs of compliance with the new regulations and must demonstrate that the costs are justified. The economic survey should include, but not be limited to, the cost of having to conduct two-step MIT testing across all types of UIC activity, as currently proposed by the regulations. This review should examine potential rates of lost production to the state, costs of compliance to operators, and whether there are sufficient service companies available to conduct the MIT tests in a timely fashion across all types of operations

as proposed. As part of this effort, Commenters believe that DOGGR should examine the failure rates of production wells that are subject to maintenance steaming or cyclic steam for connectivity purposes. An accurate understanding of the “risk” posed by this class of wells will help inform DOGGR and the public determine whether the prospective costs are reasonable.

Response to Comment 0014-24: ACCEPTED IN PART. Consistent with the requirements of the Administrative Procedure Act and applicable California Department of Finance regulations, the Division prepared a Standardized Regulatory Impact Assessment (SRIA) as part of the rulemaking process. The SRIA was included with the Initial Statement of Reasons as “Attachment A.” The SRIA analyzes costs associated with each part of the proposed regulations as initially proposed in July of 2018 and provides an estimate of the cost impact of the regulations on industry. As described in the SRIA, the cost data are based, in large part, on information obtained from an operator survey that requested estimates for the various cost drivers in the proposed regulations.

Regarding rig availability, as part of its stakeholder outreach the Division contacted a number of well service providers in California to discuss the general concerns raised by the commenter. Based on feedback from these well service operators, the Division anticipates that, though there may be short term staffing constraints, over a span of a few years the supply of rig equipment and well services will be sufficient to meet foreseeable demands without materially frustrating the ability of injection well operators to comply with the proposed regulations.

Environmental Protection and Review

0019-1

The regulations must clarify that all groundwater in California that may now, or in the future, have beneficial uses be protected from injection activity. In order to accomplish this level of protection, the regulations must ensure protections that go beyond the federal definition of an underground source of drinking water (USDW), and fully capture the current and future realities of water use in California. Additionally, saline groundwater is an increasingly common and cost effective alternative water source in this era of drought, climate change and population growth. The aquifer exemption criteria also leave open the possibility of removing Safe Drinking Water Act (SDWA) protections for groundwater that in the future will likely serve as a source of drinking water, as the criteria fail to consider desalination, treatment and scarcity scenarios that are currently happening in California. The exemption criteria, and current exemption practices also rely heavily on the criteria that an aquifer is hydrocarbon bearing. However, the fact that geologic zones contain oil does not mean that it cannot serve other beneficial uses. For example, there are current projects in California which provide produced water for irrigation and groundwater recharge from hydrocarbon bearing zones. Additionally, there is anecdotal evidence that agricultural wells have been drilled into hydrocarbon bearing zones and are producing irrigation water in Kern County. The proposed regulations do nothing to protect water users in these scenarios. Commenter recommends the Division take a fresh look at which groundwater is protected by reconsidering the criteria for aquifer exemption, and by creating a new class of groundwater that is more protective than the federal USDW based on quantity and salinity.

Response to Comment 0019-1: NOT ACCEPTED. *Modification of the criteria for aquifer exemption is outside the scope of this rulemaking action. The criteria for aquifer exemption are established in federal law under 40 CFR part 146.4 and expanded upon in state law under PRC section 3131. Defining a new regulatory class of groundwater is also outside the scope of this rulemaking action. The proposed regulations continue and clarify the Division’s practice of identifying “freshwater” (defined as containing 3,000 mg/L or less TDS) and USDW (as defined by federal law) as categorical thresholds of regulatory significance. (See proposed section 1720.1.) As discussed in the Initial Statement of Reasons, these thresholds harmonize with existing SWRCB policy and federal law. The Division believes these thresholds provide appropriate guideposts for the protection of groundwater resources in most situations. To the extent special circumstances may call for different considerations, the Division possesses broad authority to implement case-by-case requirements as necessary to prevent damage to life, health, property, and natural resources.*

0013-2

The Division must conduct a full environmental review of the direct and indirect environmental impacts of these regulations. By allowing, for the first time, injection above the fracture pressure, the proposed regulations would legalize injection activity in many more areas than in the past. The potential effects on imperiled species and their habitats would be significant. Because of the potential for direct and indirect significant impacts to the environment that would result from adopting these regulations, DOGGR must fully study, disclose, and analyze the impacts in an environmental impact report as required under the California Environmental Quality Act (CEQA).

By facilitating extended and expanded oil and gas production in the state, particularly in some of the most carbon-intensive oil fields in the world, the proposed regulations are inconsistent with California’s mandates for rapid statewide GHG emissions reductions. The urgent need to prevent the worst impacts of climate change means that California cannot afford to extend or expand oil and gas production in the state. DOGGR’s proposed regulations would exacerbate the state’s climate challenge by allowing oil fields to produce past their natural production lives and result in the production of fossil fuels that would have been unrecoverable but for these regulations.

Response to Comment 0013-2: NOT ACCEPTED. *The Division has determined there is no substantial evidence indicating adoption of these regulations could adversely affect any of the environmental resource areas, as listed in Appendix G of the CEQA Guidelines.*

Injection wells have been an integral part of California’s oil and gas operations for nearly 60 years. There are approximately 55,000 oilfield injection wells operating in California. These include enhanced oil recovery wells used to increase oil recovery through sustained injection or reinjection of large volumes of fluids, and wells devoted to the disposal of the “produced water” that emerges from hydrocarbon deposit areas simultaneously and commingled with the produced hydrocarbons

Past regulations require considerable case-by-case interpretation to identify appropriate project-specific requirements. Over time, this led to a general lack of transparency and inconsistent application of requirements, and, in some cases, aging regulatory constructs that have not kept up

with changing oil production method sand advancements in the understanding of threats to health, safety, and the environment.

The regulations will implement the Primacy Agreement with the US EPA to ensure its current regulations are sufficient in protecting groundwater resources. These regulations will (1) modernize, clarify, and augment the regulatory standards applicable to underground injection operations associated with oil and gas development in California; (2) ensure that injected fluids are confined to approved injection zones and that wells are not allowed to become a potential conduit for contamination of groundwater or the dilution of hydrocarbon resources; (3) ensure that underground injection operations will not result in surface expressions; and (4) specify a list of circumstances that require operators to notify the Division and cease injection until the Division authorizes resumption.

The provisions in these regulations regarding injection above fracture pressure are an example of how these regulations achieve these goals and address past practice. The existing provisions in Section 1724.10(i) addressing injection above fracture pressure are specific to sustained liquid injection, and injection above fracture pressure is common for cyclic steam injection operations in diatomite formations. The new requirements of Section 1724.10.3 include performance standards and a regulatory framework to address such operations to surface expressions and otherwise ensure protection of life, health, property, and natural resources.

These regulatory amendments are designed to protect natural resources and the environment, and overall would enhance protection of life, health, property, natural resources, and the environment, and there will be no physical change in the environment resulting from compliance with the amendments.

0013-16

DOGGR admits it has “ongoing discretion” to allow underground injection projects. Approval over discretionary projects requires adherence to the California Environmental Quality Act (CEQA). Despite the well-documented environmental impacts of EOR and wastewater disposal, in the past DOGGR has failed to conduct an environmental review of any kind regarding these projects, and the proposed regulations do not indicate that DOGGR intends to conduct any sort of project-level environmental review in conjunction with its approval of underground injection projects going forward. DOGGR must conduct adequate environmental review on the project level, and an analysis of the cumulative impacts of authorizing underground injection projects statewide.

Response to Comment 0013-16: NOT ACCEPTED. *The Division does not see a need to address within the proposed regulations the application of the California Environmental Quality Act (CEQA) to the Division’s process for approval of underground injection projects. Determinations regarding the appropriate environmental review associated with approval of an underground injection project are made at the project level as part of the approval process. Typically, local entities act as CEQA lead agencies for oilfield-related projects, including underground injection projects, and the Division acts as a responsible agency.*

Field Rules

0009-2, 0014-19a

The regulation should take into consideration the unique site-specific geologic conditions that exist in many of the state's oil fields, and where appropriate, retain the longstanding ability for division staff and operators to apply field-specific rules in place of statewide standards.

Response to Comments 0009-2 and 0014-19a: NOT ACCEPTED. The Division believes the proposed regulations strike an appropriate balance between prescriptive clarity and project-specific flexibility. In many instances, the proposed regulations allow operators to propose and, with Division approval, employ alternatives to the default regulatory requirements, as long as the alternative meets the prescribed performance standard. Examples of this flexible, performance standard based approach within the proposed regulations include: alternative requirements for project data to demonstrate confinement of injected fluid (§ 1724.7, subd. (e)); alternative AOR review demonstration for idle wells not abandoned to current standards (§ 1724.8, subd. (a)(3)); optional use of packer technical equivalents to isolate production tubing from casing (§ 1724.10, subd. (g)); alternative procedures for initial and periodic mechanical integrity testing (§§ 1724.10.1, subd. (c) and 1724.10.2, subd. (c) and (d)).

High Frequency Requirements

0014-27

The draft regulations would require testing, monitoring or data recording at unnecessarily high frequencies (e.g., every second, every five minutes, etc.). Some of these requirements are overly burdensome to the point where the operation becomes infeasible or noneconomic (e.g., the new requirements to hold pressure on the casing-tubing annulus associated with alternative annular pressure monitoring) without any corresponding improvement to safety. Operators have already made significant investments in monitoring equipment and process changes approved by DOGGR, and DOGGR should not impose additional requirements on operators where the high cost of compliance undermines the economic feasibility of the original investment, without materially improving the safety of the activity or well.

Response to Comment 0014-27: NOT ACCEPTED. The Division's existing regulations require that injection wells be equipped for installation of a pressure gauge or pressure recording device. Proposed section 1724.10.4 modernizes the requirement by calling for operators to continuously record injection pressures at all times that a well is injecting. The requirement may be satisfied by recording injection pressure from a header or manifold, if the operator demonstrates the ability to calculate well-specific injection pressures from the recorded data.

Continuous injection pressure data will be beneficial when the Division is investigating incidents such as surface expressions or concerns about potential groundwater contamination. The data will also enable the Division to verify compliance with other injection reporting requirements and with MASP requirements. To facilitate the Division rapidly flagging MASP compliance concerns, operators are required to report the highest instantaneous injection pressure for each injection well each month. The current requirement that a pressure gauge or recording device "be available at all times" does not

yield useful data for such investigations and compliance checks. Instead, the current regulation only allows the Division to obtain a pressure reading at one specific point in time, and the Division must take additional steps such as making a site visit or request that the operator take a gauge reading. If the injection facilities for an injection well are configured in a manner that effectively prevents injection above the maximum allowable surface injection pressure, then the necessity for continuous injection pressure is largely addressed and the Division may waive the requirement for that well. And an operator may always suspend continuous injection pressure recording for a well while the well is disconnected from all injection lines.

Recognizing that for many existing injection wells new equipment will be needed to comply with these requirements, proposed section 1724.10.4, subdivision (b), affords operators until April 1, 2021 to meet the new requirements. In the interim, operators are required to continue to comply with the existing requirement to ensure that an accurate, operating pressure gauge or pressure recording device is available at all times, and that injection wells are equipped for installation and operation of such gauge or device.

Under the current proposed section 1724.10.1, the alternative pressure testing and monitoring program referenced in the comment is not a requirement; it is an optional alternative to conducting a pressure test of the casing to MASP. Additionally, proposed section 1724.10.1, subdivision (d), contemplates that operators may use other alternative mechanical integrity testing methods to satisfy the pressure testing requirements of proposed section 1724.10.1. Use of such alternative methods would require case-by-case approval from the Division, based on a determination that the alternative method is at least as effective as the prescribed methods for demonstrating the integrity of the well under an appropriate pressure.

Public Notice and Comment

0013-4, 0013-15

Oil and gas in California is an environmental justice issue. Low income communities of color have historically borne a disproportionate burden of exposure to oil and gas pollution. In California, of the 5.4 million residents living within one mile of a well, nearly 69 percent are people of color. The public, especially the communities most directly affected by potential adverse effects of injection projects, must be allowed the opportunity to voice their concerns over projects. The regulations leave unclear if and when the public will be granted an opportunity to comment on proposed injection permits. The Division should establish public notice and comment procedures for injection permits and project approval letters.

Response to Comments 0013-4 and 0013-15: NOT ACCEPTED. *The Division routinely solicits input from all interested members of the public, and particularly welcomes comments from the residents of communities situated near oil and gas operations. Consistent with the Division's April 1981 "Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act," and the subsequent Primacy Agreement between the Division and the US EPA, it is Division policy and practice to publish in a regionally available newspaper a notice inviting public*

comment regarding each request for approval of a new underground injection project or for approval of substantial changes to an existing underground injection project. The Division does not see a need to codify this policy within the proposed regulations. Other forms of notice and opportunities for comment regarding underground injection projects also may arise in connection with applicable local agency approvals, and any applicable environmental review procedures undertaken by the appropriate lead agency.

0019-1

The current scheme of exempting aquifers, and/or permitting injection projects, does not require notification to potential groundwater users in the area. A land owner could drill a water well, or deepen an existing well, without any knowledge that an oil company is using underlying groundwater as an injection zone. Because neither Division nor operators have provided accurate maps of exempted aquifers or injection zones to both county health departments (who permit water well drilling), nor landowners, there is a very real possibility that water wells and injection wells could occupy the same aquifers, leading to well contamination. Furthermore, the drilling or deepening of water wells without injection zone information, and the appropriate well construction requirements, could create new pathways for contamination between injection zones or exempt aquifers, and protected groundwater, including USDWs. Commenter recommends the Division establish a system for public notification and dissemination of detailed information of which groundwater is being used as injection zones and/or has been exempted from protection.

Response to Comment 0019-1: NOT ACCEPTED. *A comprehensive groundwater and subsurface formation mapping system of the type contemplated by the commenter is outside the scope of this rulemaking action. On its public website, the Division currently makes available extensive information about injection wells within California, including their location, history, associated log data, status, and reported injection volumes. Collaborating with state and local agencies responsible for permitting water wells, to ensure their safe construction and use, is a Division priority.*

COMMENTS BY SECTION

1720.1 **Definitions**

0019-10

1720.1: Commenter recommends adding definitions for “enhanced recovery” and “disposal”.

Response to Comment 0019-10: NOT ACCEPTED. *Proposed section 1720.1 already includes a definition for “disposal injection well.” The use of the term “enhanced oil recovery” in the proposed regulations is consistent with its ordinary meaning. This term appears only as part of the definition of “underground injection project.” It is not a term possessing independent regulatory significance within the proposed regulations.*

0018-1

1720.1: This section does not appear to include a definition of air injection wells. While no such wells may be in operation currently, their definition should be included for completeness and because such wells existed in the past.

Response to Comment 0018-1: ACCEPTED IN PART. *The defined term “underground injection project,” at proposed section 1720.1, subdivision (p), describes the range of injection operations*

subject to the proposed regulations. This definition includes a non-exhaustive list of project types as illustrative examples. In the First Revised Text of Proposed Regulations, the Division added to the list of examples “carbon dioxide enhanced oil recovery.” The Division added this example to clarify that this type of injection operation is an underground injection project within the scope of the proposed regulations. The Division does not see a present need to add a regulatory definition for “air injection well.” The proposed regulations do not use the term “air injection well” or otherwise specifically reference air injection.

0018-2

1720.1: This section should define water source wells and water supply wells as they are mentioned in other sections of the draft regulations.

Response to Comment 0018-2: ACCEPTED. *The Division has added definitions for “water source well” and “water supply well” as proposed section 1720.1, subdivisions (r) and (s).*

0013-11

The Area of Review (AOR) that needs be evaluated and reported to DOGGR is insufficient to ensure that groundwater is protected. Federal regulations require a minimum fixed radius of a quarter-mile unless an approved mathematical model is used to determine the zone of endangering influence (ZEI). (40 C.F.R. § 146.6.) The proposed regulations improperly allow DOGGR to unilaterally change the AOR based on “any factors” DOGGR finds relevant, even if it results in a shorter distance than the federal minimum of a quarter mile. Such open-ended, criteria-free standards are expressly prohibited under federal regulations. (40 C.F.R. § 146.6(a)(2) and (c).)

Any amendments to California’s law relating to the UIC Program and Class II wells must be consistent with, or “at least as stringent as the corresponding listed provisions” in the SDWA and the Federal Regulations. (40 C.F.R. § 145.11(b)(1).) Accordingly, if the proposed regulations are not in conformance with, or are less stringent than, the specified provisions of the Code of Federal Regulations, DOGGR is in violation of federal law.

Response to Comment 0013-11: NOT ACCEPTED. *The Division believes that in many situations AOR is best defined by the calculated lateral distance that injection fluid or reservoir fluid may migrate. As articulated in proposed section 1720.1, subdivision (a), and as further discussed the Initial Statement of Reasons, this calculation may be based on injection zone pressure, temperature, and other project-specific data, as necessary to ensure that the area of review is at least as broad as the area that is, or would be, influenced by injection. Alternatively, AOR may be defined by reference to a fixed area of a one-quarter-mile radius around the injection well, as long as that shorthand metric achieves the performance standard identified in the regulatory text: i.e., “to ensure that the area of review is at least as broad as the area of influence.” Where AOR calculations indicate that a distance of less than a quarter-mile is the appropriate AOR, the lesser distance may be used. This approach is broadly consistent with similar a similar federal regulation regarding AOR referenced in the comment. (See 40 CFR § 146.6.)*

The assertion that the definition of “AOR” in the proposed regulations conflicts with or “violates” federal law is incorrect, both as to details and as to foundational assumptions. First, on the details, contrary to what the comment suggests, 40 CFR § 146.6 neither prescribes a specific method for calculating AOR, nor does it set a one-quarter-mile radius as the minimum for an AOR. The AOR

calculation formula appearing in 40 CFR § 146.6(a)(2) is an example rather than a requirement. As stated in the regulatory text, “[c]omputation of the zone of endangering influence may be based on the parameters listed below,” and the equation listed merely “illustrates one form which the mathematical model may take.” Similarly, like the proposed regulations, 40 CFR § 146.6(c) clearly contemplates that a calculated AOR (using an appropriate, but not prescribed, method) may be less than the fixed one-quarter-mile radius alternative option. Second, as to foundational assumptions, this comment is rooted in the incorrect presumption that various federal regulations appearing in 40 CFR parts 145 and 146 have direct application to the Division or to the Division’s administration of the class II UIC program for California. That is not the case. As a program authorized under “section 1425” of the SDWA (see 40 CFR § 147.250), the class II UIC program administered by the Division is not subject to the same federal statutory and regulatory provisions that apply to UIC programs authorized under “section 1422” of the SDWA. The overall thrust of the comment reflects a fundamental misunderstanding of the important distinctions between UIC programs authorized under “section 1425” and “section 1422” of the SDWA. Helpful explanation of these distinctions may be found in the US EPA’s Ground Water Program Guidance #19, titled “Guidance for State Submissions Under Section 1425 of the Safe Drinking Water Act.”

0008-2

1720.1(a): There is no scientific justification for allowing operators to select a quarter-mile fixed radius for the area of review (AOR). This radius is arbitrary and has no basis in the geologic properties of the injection formation, the volume and pressure of the injection fluid, or the type of injection activity. This option should be eliminated. First, given that it is arbitrary there are likely to be few if any circumstances where the quarter-mile radius would accurately reflect the potential scope of injection fluid migration. Second, federal rules allow for deviation from federal Class II standards as long as the standards protect USDWs. Given that the quarter-mile fixed radius has not scientific basis and has been criticized by US EPA’s own scientists as inadequate to protect USDWs, eliminating the use of any fixed-radius AOR would actually be most protective of USDWs and therefore most aligned with the goals of SDWA. The currently proposed definition for area of review should be replaced with the proposed definition of injection zone. The Division should also explicitly state that the AOR can be drawn from a single well or can encompass many wells.

Response to Comment 0008-2: ACCEPTED IN PART. *The Division agrees that an AOR must be large enough to encompass the anticipated scope of injection influence. The Division also sees value in preserving fundamental commonality between the definition of AOR in the proposed regulations and in existing federal regulations of similar function.*

The definition of “AOR” at proposed section 1720.1, subdivision (a), has been amended by the addition of language articulating a performance standard that will guide determination of the AOR for each injection well: “to ensure that the area of review is at least as broad as the area of influence.” As amended, while the AOR definition still contemplates that operators may propose a fixed one-quarter-mile radius rather than a specifically calculated lateral distance, in either case the Division may specify an AOR different than the operator’s proposal, as necessary to achieve the performance standard. Consequently, under the proposed regulations, the fixed radius AOR will be an option only when

sufficient information exists to satisfy the Division that it is adequate to ensure the area of review is at least as broad as the area that is, or would be, influenced by the injection.

The current definition of AOR in the proposed regulations encompasses the area “within and beyond the intended injection zone to which pressures or temperatures in the intended injection zone may cause the migration of injected fluid or the reservoir fluid.” The Division believes this definition has adequate and sufficiently clear application to scenarios involving single and multiple wells.

0019-6

1720.1(a): The AOR must be inclusive of the area that could experience pressure changes, regardless of whether or not it is inside the injection zone. Pressure changes outside the injection zone could create conduits for fluid migration and cause contamination or formation damage. The inclusion of a quarter-mile radius in the AOR definition requires more specificity, including clarity about when the fixed radius is appropriate to use. We recommend that the AOR only be a fixed quarter-mile radius if a quarter mile is greater than the calculated lateral distance defined above. Additionally, if a fixed radius is used, the center of the radius must be defined as the entirety of the wellbore to account for directional or horizontal wells.

Recommended edits – “...*The area of review is whichever of the following is a greater distance: either: (1) The calculated lateral distance encompassing within and beyond the intended injection zone to which the pressures ~~in the intended injection zone~~ may cause the migration of the injection fluid or the formation fluid or create new or modify existing pathways; or (2) A fixed one-quarter mile radius from the path of the wellbore.*”

Response to Comment 0019-6: NOT ACCEPTED. *The Division will evaluate the geology and engineering elements of each underground injection project to determine the appropriate AOR based on the potential for fluid migration, and will not allow the use of the quarter-mile AOR unless it can be demonstrated that it will include any and all areas subject to potential fluid migration. This is reflected in and clarified by the addition of a performance standard to the text of the originally proposed section 1720.1., subdivision (a), AOR definition: “to ensure that the area of review is at least as broad as the area of influence.” The definition as proposed already accounts for migration of injection fluid as well as reservoir fluid. The example of the pressure changes outside the injection zone creating conduits is encompassed by this framework.*

0018-4

1720.1(a): Commenter believes this is a more stringent definition than the US EPA. That definition is pressure sufficient to cause fluid to migrate from the injection zone to USDW via a hypothetical conduit connecting them that is laterally impermeable between them. This can require a finite minimum pressure depending upon conditions in the boring. In comparison, an infinitesimal pressure change will cause some migration. Consequently, the proposed definition would seem to result in much larger AORs than under the US EPA’s definition, at least for disposal projects.

Response to Comment 0018-4: NOT ACCEPTED. *Requiring an AOR larger than what might be required under similar federal regulations is an intended feature of the proposed regulations. In its current form, proposed section 1720.1, subdivision (a), links determination of an AOR to a performance standard: “to ensure that the area of review is at least as broad as the area of influence.” The Division*

believes the proposed definition of AOR is appropriately tailored and will aid the Division in achieving its regulatory mission.

0018-5

1720.1(a): There is no scientific basis for the fixed one-quarter mile radius definition of AOR. Given the well spacing in some EOR projects, the area of pressure resulting from an individual injection well may be smaller due to production wells being in closer proximity than 1,320 feet.

Response to Comment 0018-5: ACCEPTED IN PART. *The Division agrees that an AOR must be large enough to encompass the anticipated scope of injection influence. The Division also sees value in preserving fundamental commonality between the definition of AOR in the proposed regulations and in existing federal regulations of similar function, which include a similar fixed radius option.*

The definition of “AOR” at proposed section 1720.1, subdivision (a), has been amended by the addition of language articulating a performance standard that will guide determination of the AOR for each injection well: “to ensure that the area of review is at least as broad as the area of influence.” As amended, while the AOR definition still contemplates that operators may propose a fixed one-quarter-mile radius rather than a specifically calculated lateral distance, in either case the Division may specify an AOR different than the operator’s proposal, as necessary to achieve the performance standard. Consequently, under the proposed regulations, the fixed radius AOR will be an option only when sufficient information exists to satisfy the Division that it is adequate to ensure the area of review is at least as broad as the area that is, or would be, influenced by the injection.

0014-30

1720.1(a): Commenter believes that, consistent with federal UIC requirements, an AOR should be able to be determined on the basis of a group of wells that are proposed as part of a single project, particularly where the wells are in-fill in an existing, already heavily developed field. Depending on the number and spacing of the wells, the determination of multiple overlapping AORs is burdensome and unnecessary. Commenter recommends that the state provide the opportunity to demonstrate on a case-by-case basis that a project level AOR is protective. Commenter also believes that fixed guidelines or criteria need to be established for defining the AOR. As currently drafted, the language in subsection (a)(1) that refers to the potential for migration of injection fluid is very open-ended, leaving the boundaries of the AOR very ill-defined. Further, if interpreted literally, the language as drafted could be interpreted to apply to the first barrel of fluid placed into the injection zone, which necessarily displaces formation fluid in the reservoir, forcing it out of the intended zone of injection.

Response to Comment 0014-30: ACCEPTED IN PART. *The definition of “AOR” at proposed section 1720.1, subdivision (a), has been amended by the addition of language articulating a performance standard that will guide determination of the AOR for each injection well: “to ensure that the area of review is at least as broad as the area of influence.” The intent of proposed section 1720.1 is to ensure that each AOR is adequately large, not to require unnecessary calculations when an adequately large AOR has been specified. If an operator can demonstrate that a proposed AOR covering all injection wells within an underground injection project encompasses an area around each injection well that is broader than the calculated lateral distance as described in proposed section 1720.1, subdivision (a), then the proposed AOR may be acceptable.*

The Division does not agree that a more rigid regulatory prescription for determining project-specific AOR would be beneficial. Operators and Division staff will evaluate the geology and engineering elements of each underground injection project to determine the appropriate AOR based on the potential for fluid migration. Federal regulations defining AOR adopt a similarly flexible or “open-ended” approach to specifying how AOR may be determined. (See 40 CFR § 146.6(a)(2), noting that provided equation for determining zone of endangering influence is intended to be exemplary, and merely “illustrates one form which the mathematical model may take.”)

0018-48

1720.1(b): Commenter rewrites this section as follows: “Cyclic steam injection well” means an injection well by which ~~that injects~~ steam is injected into an underground formation and from which a ~~then subsequently produces~~ hydrocarbons are subsequently produced.

Response to Comment 0018-48: NOT ACCEPTED. *Commenter’s changes do not add to or clarify the meaning of the regulatory language.*

0007-1

1720.1(e): Add language to the definition “freshwater does not include Federal EPA exempted USDW”. This clarification ensures that waters that have been exempted by Fed EPA and have a TDS of 3,000 and below are not included in the freshwater definition.

0014-31

1720.1(e): The need to protect “freshwater” is based on the designated actual and reasonably foreseeable beneficial uses of such water. However, water that contains less than 3,000 TDS but that is co-located with petroleum hydrocarbons in a hydrocarbon-producing reservoir that is an exempt aquifer has no actual or reasonably foreseeable beneficial uses. Accordingly, water with 3,000 TDS or less that occurs in this geologic setting should be excluded from the definition of “freshwater.”

Response to Comments 0007-1 and 0014-31: NOT ACCEPTED. *Understanding subsurface conditions is important for effective regulation of underground injection projects. The Division sees regulatory value in requiring operators of underground injection projects to provide various cross sections, electric logs, and casing diagrams identifying the location of geologic units containing freshwater. See proposed section 1724.7, subdivisions (a)(2)(E) and (F), and proposed section 1724.7.1, subdivision (a). The potential that a geologic unit could simultaneously contain “freshwater” as defined in the proposed regulations and also be designated exempt from classification as a USDW by the US EPA does not present a conflict.*

0014-32

1720.1(f): Commenter believes the definition of “injection well” should be revised to ensure there is clarity around the applicability of the regulations to disposal activities.

Response to Comment 0014-32: NOT ACCEPTED. *The Division believes the application of the proposed regulations to disposal injection wells is sufficiently clear. As used within the proposed regulations, the term “injection well” is intended to be a broad catchall for various types of wells, each of which have a more specific definition in the proposed regulations. The proposed regulations already include a definition for “disposal injection well,” at proposed section 1720.1, subdivision (c). Additionally, the definition of “underground injection project,” at proposed section 1720.1, subdivision (p), specifically references injection for the purpose of disposal.*

0014-33

The definition of “mechanical integrity” should be revised to reflect the fact that not all wells have packers.

***Response to Comment 0014-33: NOT ACCEPTED.** The definition of “mechanical integrity” in proposed section 1720.1, subdivision (i), references packers as part of a non-exhaustive list of things that may act as mechanical well barriers to contain pressure. This reference to packers and other components is a set of illustrative examples; it is not a prescriptive itemization of components required to assure mechanical integrity in every situation. The Division believes definition of “mechanical integrity” is sufficiently clear on this issue.*

0011-1, 0015-1

1720.1(f) and (m):

The recently adopted regulations for underground gas storage projects include language in Section 1726 that states “underground gas storage projects and gas storage wells are not subject to the requirements of Sections 1724.6 through 1724.10.” For consistency, commenters recommend modifying the proposed regulations by adding to the definitions of “injection well” and “underground injection project” a mirrored explicit exclusion for underground gas storage projects. For similar reasons, one commenter also recommends deleting the word “storage” from the definition of underground injection project.

0018-3

1720.1(m): Do these regulations also apply to gas storage projects, which I believe were previously not covered by California’s UIC regulations? If so, this is the only mention of storage. A definition of gas storage well should be added. It would be useful to include reference to the gas storage regulations somewhere. If these regulations do not apply to gas storage, I suggest deleting this reference.

***Response to Comments 0011-1, 0015-1, and 0018-3: ACCEPTED IN PART.** The Division has modified the definitions of “injection well” and “underground injection project” by adding the following clarifications.*

- *Proposed section 1724.1, subdivision (f): Added “A gas storage well, as defined in Section 1726.1(a)(4), is not an injection well.”*
- *Proposed section 1724.1, subdivision (p): Added “An underground gas storage project, as defined in Section 1726.1(a)(6), is not an underground injection project.”*

Further, the Division has added proposed section 1724.5, describing the purpose, scope, and applicability of the UIC regulations, which includes the following statement: “Underground injection projects and injection wells are not subject to the requirements of Article 5, Sections 1726 through 1726.10.”

Regarding use of the term “storage” in the definition of “underground injection project,” some underground injection projects involve injection associated with storage of liquid hydrocarbons. To reduce the potential for confusion about what type of storage is meant within the definition of an underground injection project, the Division has changed “storage” to the more specific “storage of liquid hydrocarbons.”

0002-7

Commenter requests clarification and recommends refining the definition to specify what a “three-dimensional space” means, as used in the definition of “injection zone.”

Response to Comment 0002-7: NOT ACCEPTED. The use of the term “three-dimensional space” in the regulations is consistent with its dictionary definition of “having or appearing to have length, breadth, and depth.” It is intended to describe the physical space that will be designated as an injection zone, and to indicate that the space will be measured spherically rather than linearly.

0019-7

Commenter urges the definition of injection zone to include stronger zonal isolation requirements to ensure that fluids cannot migrate into groundwater that have beneficial uses. Specifically, operators must be able to demonstrate that impermeable layers provide adequate separation. Recommended text: “...with fixed boundaries that can be demonstrated to be geologically confined by impermeable layer(s) where fluid injected...more than one formation or strata. The injection zone must be geologically separated from any groundwater that may have beneficial uses.”

Response to Comment 00019-7: NOT ACCEPTED. The fixed boundaries of an injection zone need not always be coextensive with impermeable geologic layers. For example, in some situations a hydraulic gradient may provide a sufficient barrier to fluid migration and be used to define a portion of an injection zone boundary. In general, the project data requirements found in proposed section 1724.7 require collection and analysis of the type of confinement assurance information the commenter references. A primary reason for requiring operators to provide the data described in proposed section 1724.7 is to ensure that each underground injection project is, on whole, supported by data demonstrating that the injected fluid will be confined to the approved injection zone.

0002-15, 0014-8, 0017-4

proposed regulations should be rewritten in a manner that aligns with the EPA Title 40 Federal Regulations (144.28.f.6.ii and 146.23.a.1), which focus on having a barrier between USDW and hydrocarbon zones below. Migration out of the approved zone should only be prohibited when there is no containment between the intended injection zone and protected fresh waters.

0014-25

As drafted, the regulations prohibit any migration of injection fluids outside the approved zone or zones of injection, without exception. This prohibition goes beyond the requirements of the federal UIC program, which focus on protection of sources of drinking water by prohibiting movement of fluids into USDWs as distinguished from movement of fluids out of the approved zone of injection. The requirement that injection fluids remain in the approved zone of injection is unnecessary and unduly restrictive in certain geologic settings, where there is no risk to either protected waters or to the reservoir. A flat prohibition against any out-of-zone movement of injection fluids provides no additional benefit in terms of protecting USDW zones and other waters with beneficial uses, and will result in undue economic pressure on operators. DOGGR should clarify in the draft UIC regulations that a confining barrier between the hydrocarbon zone and USDWs or water with other beneficial uses is required to maintain protection of usable water resources and to prevent damage to hydrocarbon reservoirs, consistent with DOGGR’s dual mandate in PRC section 3106. At a minimum, the regulations should be revised to allow DOGGR to grant exceptions to the “no migration” standard, as documented in a Project Approval Letter.

Response to Comments 0002-15, 0014-8, 0017-4, and 0014-25: NOT ACCEPTED. Confinement of injected fluids to an approved injection zone is, and long has been, the cornerstone performance standard of the Division’s regulatory program for underground injection projects under existing regulations. The proposed regulations clarify that standard but do not depart from it. The definition of “injection zone” at proposed section 1720.1, subdivision (g), notes that the boundaries of the injection zone are intended to indicate the complete three-dimensional space where injected fluid is anticipated to be located, and that this space may encompass more than one formation or strata. Rather than requiring “no migration” beyond an arbitrary point, as the commenter posits, the relevant task is to identify accurately the boundaries of an area that fully encompasses the anticipated migration of injected fluids, and then to assess any potential risks injection into that area would present. Depending on the identified potential risks, an approved underground injection project may be subject to operational conditions that serve to limit the area where injected fluids are anticipated to be located—thus shaping what becomes the approved injection zone. The Division believes the commenter’s concerns regarding unnecessarily restrictive limitations on injection can be adequately addressed in each instance by identifying the appropriate injection zone boundaries, based on the applicable geology and operational conditions.

0018-49

1720.1(g): Minor text edit, change “where” to “the”

Response to Comment 0018-49: NOT ACCEPTED. This comment would result in a meaningless sentence “...with fixed boundaries the fluid...” “Where” is a needed term in that phrase.

0018-50

1720.1(h): Minor text edit, “...well barriers to fluid migration envelopes...”

Response to Comment 0018-50: ACCEPTED IN PART. “Envelopes” has been removed and “mechanical” has been added so that the phrase reads, “...all mechanical well barriers...”

0002-8

1720.1(k) Commenter suggests that the definition of “surface expression be changed as follows, to reflect the presence of naturally occurring seeps: “...wellbore and that appears to be is directly attributable to caused by injection operations.”

0002-11

Commenter recommends adding the following definition for the term “seep,” to ensure naturally occurring seeps are not considered surface expressions: “Seep” means a flow, movement or release, or low pressure (gravity drainage), ambient temperature fluid such as oil and water from the shallow subsurface, but critically not from the zone of injection

0009-1

1720.1(k) and 1724.11(d): Commenter is concerned about distinguishing between natural seeps and those caused by injection, finding the phrase in the existing regulations to be too ambiguous for clarity. Commenter has worked closely with the Division to establish using crude oil fingerprinting that seep oil is not from the zone of injection. Furthermore, for any individual seep, it is not possible to determine if the seep has been caused indirectly by injection operations, or by other factors i.e. rainfall, natural tectonic uplift, solar heating etc. Clearly, if a cluster of seeps occur in a short period of time in the vicinity of cyclic steaming operations, and ground movement is recorded, then it is reasonable to conclude that injection operations have indirectly accelerated the occurrences of the

seeps. However, the proposed definition of surface expression is so broad as to include all forms of surface anomalies, from high-heat, high-flow (and extremely hazardous) expressions emanating directly from the injection zone or from shallow well casing leaks, to low-heat, low-flow, indirect occurrences, without regard to the intensity of the anomaly and the corresponding risk. The shut-in requirement as written in 1724.11. (d) has the potential to inflict economic harm to Commenter without a corresponding reduction in risk to health, safety, property, and the environment. Thus, commenter requests a separate definition for seeps that specifies ambient temperature fluid NOT from the zone of injection. In the absence of any change to definitions, commenter requests that language be added to 1724.11. (d) to provide relief from the shut-down requirements for low-energy seeps.

Response to Comments 0002-8, 0009-1, and 0002-11: ACCEPTED IN PART. *The definition for surface expression remains unchanged, but the proposed regulations have been modified elsewhere to better distinguish and account for the meaningful regulatory differences that exist between some surface expression scenarios. Specifically, a new term, “low-energy seep,” has been added, at proposed section 1720.1, subdivision (h). This term applies to surface expressions where the fluid coming to the surface is not injected fluid, is not hot, is not being released to the surface with high energy and has been contained to ensure it does not pose a safety risk. Under the proposed regulations, the existence of a surface expression that fits these criteria will not be considered a violation of the general prohibition of surface expressions. See proposed sections 1724.11, subdivision (j) and 1724.12, subdivision (b).*

0014-28

The draft definition of “surface expression” includes several examples that describe natural phenomena that do not necessarily occur as a result of injection operations. Commenter recommends that the examples be deleted, allowing operators the ability to evaluate surface expressions on a case-by-case basis to determine whether they fall within the scope of the regulations.

Response to Comment 0014-28: ACCEPTED. *This comment refers to an early, pre-rulemaking discussion draft version of the proposed regulations, within which a definition for the term “surface expression” included various examples. The definition of “surface expression” now appearing at proposed section 1720.1, subdivision (n), does not include the examples referenced by the commenter.*

0018-51

1720.1(j): Minor text edits “...an injection well by which ~~that injects~~ steam is injected into an underground...enhancing the hydrocarbon recovery from ~~of~~ other producing...”

Response to Comment 0018-51: NOT ACCEPTED. *Commenter’s changes do not add to or clarify the meaning of the regulatory language.*

0018-6

1720.1(k): Recommended edits: “...from the subsurface to ground surface or atmosphere outside of a well of fluid...”

Response to Comment 0018-6: NOT ACCEPTED. *The text is clear as proposed; the surface being referred to could only be the ground and release from the surface would necessitate going into the atmosphere outside of a well.*

0007-2

Commenter suggests changing the definition of “surface expression” from a release “that appears to be caused by injection operations” to a release “that has been caused by injection operations.” Commenter argues that the phrase “appears to be” allows for interpretation that does not recognize the importance of engineering and science in determining if injection caused the surface expression, and could be misinterpreted by individuals. Commenter believes “has been caused by” provides a more technical, science and engineering based performance standard for identifying a surface expression.

Response to Comment 0007-2: NOT ACCEPTED. Recognition of at least temporary causal uncertainty within the definition of “surface expression” is an intended and important component of how the Division will exercise its regulatory discretion to ensure that surface expressions are prevented entirely when possible, and safely contained if they occur. The phrase “appears to be caused by” reflects the reality that the relationship between a surface expression and injection activity may not always be immediately apparent. Determining a causal relationship may require investigation. Proposed sections 1724.11 and 1724.12 require the operator to implement a suite of precautionary measures in the event a surface expression occurs near one of its injection wells. For these precautionary measures to be effective, they must be undertaken promptly upon the detection of a surface expression, and not be delayed pending the outcome of an investigation.

To the extent the commenter is concerned that the definition of “surface expression” does not distinguish natural seeps from other types of surface expressions, the Division believes it has adequately addressed such concerns with the addition of the “low-energy seep” definition at proposed section 1720.1, subdivision (h), and the related low-energy seep exception to the prohibition of surface expressions, as codified in proposed sections 1724.11, subdivision (j) and 1724.12, subdivision (b).

0014-34

The definition of “surface expression containment measure” identifies earthen ditches and containment berms as examples of engineered measures to contain or collect fluids from a surface expression. These two examples should be deleted because they are not engineered measures.

Response to Comment 0014-34: NOT ACCEPTED. Earthen ditches and containment berms must be designed to ensure they will properly contain the surface expression. Thus, they must be engineered for their specific purpose. These terms are appropriately retained in this definition.

0002-9, 0007-4

1720.1(m) “Underground injection project”: Commenter requests the definition be amended to clarify that a single well does not constitute a project. If within an approved area, one well would simply require a Notice of Intent from DOGGR. Commenter believes treating single wells as projects will likely result in permitting delays and declined production. “...recurring injection into ~~one~~ two or more wells...”

Response to Comments 0002-9 and 0007-4: NOT ACCEPTED. The Division believes the term “underground injection project” is appropriately defined in the proposed regulations. The operation of a single injection well presents many of the same regulatory concerns as does the coordinated operation of several injection wells. The Division does not see a regulatory need to establish a separate set of requirements for underground injection projects consisting of a single injection well, or to craft a

separate definition for underground injection projects consisting of a single injection well only to then apply the same requirements.

0014-35

1720.1(m): Historically, only a letter to DOGGR and notification to offset operators was required for cyclic steaming. It is unclear under the draft regulations whether separate project applications and Project Approval Letters are needed for cyclic and dedicated steam flood operations that occur in the same area and interval. The two often occur together, and requiring the preparation and maintenance of two project applications would be unnecessarily burdensome for operators and regulators. Commenter seeks confirmation that different types of injection operations that occur within a single underground injection project may be covered by a single Project Approval Letter under the updated regulations.

***Response to Comment 0014-35: NOT ACCEPTED:** The proposed regulations are intentionally flexible regarding the assortment of injection wells that may be grouped within an underground injection project. The Division anticipates that, in practice, many underground injection projects will include only injection wells of a single type. In some cases, however, it may be appropriate for multiple types of injection wells to be included in a single underground injection project under a single project approval letter. The proposed regulations are sufficiently flexible to accommodate both situations.*

0019-8

1720.1(m): The proposed regulations do not mention CO₂-EOR or thermal recovery. In general, the regulations lack specific requirements for different types of injection projects, whether recovery methods or disposal. Each type of enhanced oil recovery and disposal have specific risks and operational differences that may necessitate unique requirements. The proposed regulations do not account for these differences. For example, we recommend that these regulations specify that CO₂-EOR operations must obtain a permit under a regulatory scheme specifically designed to handle the injection of CO₂, such as the Air Resources Board's proposed carbon capture and storage protocols under the Low Carbon Fuel Standard, the UIC Class VI program, or another regulatory program designed specifically for CO₂-EOR. These regulations should specify that Class II regulations alone may not be applied to such a project. Recommended text: "...cyclic steam injection, thermal recovery, carbon dioxide enhanced oil recovery (CO₂-EOR), and disposal injection."

***Response to Comment 0019-8: ACCEPTED IN PART.** The defined term "underground injection project," at proposed section 1720.1, subdivision (p), describes the range of injection operations subject to the proposed regulations. This definition includes a non-exhaustive list of project types as illustrative examples. In the First Revised Text of Proposed Regulations, the Division added to the list of examples "carbon dioxide enhanced oil recovery." The Division added this example to clarify that this type of injection operation is an underground injection project within the scope of the proposed regulations. The Division does not believe the addition of "thermal recovery" to list of examples in this definition would improve clarity.*

The Division does not see a need to include within the proposed regulations an index of cross references to potentially applicable permitting requirements overseen by other local, state, and federal entities, as the commenter suggests.

0014-36

The definition of USDW should say “portion thereof” rather than “its portion.”

Response to Comment 0014-36: NOT ACCEPTED. The definition of “underground source of drinking water” appearing at proposed section 1720.1, subdivision (q), tracks verbatim the corresponding federal definition of the term appearing at 40 CFR § 144.3. Making the recommended change to the definition in the proposed regulations would introduce a difference between the state and federal definitions. The Division believes this change would tend to invite confusion rather than add clarity.

0019-9

1720.1(n): Because the definition of a USDW in these regulations aligns with the federal definition, we do not advocate any changes to the USDW definition. However, we note that the USDW definition is not adequate to protect all California groundwater with beneficial uses. First, the quantity threshold (“containing a sufficient quantity to supply a public water system”) could leave private well owners and other water users without protection. Second, the State of California routinely protects ALL beneficial uses, not just drinking water. Irrigation, aquifer recharge, industrial, and other uses for groundwater should be protected from injection as well. Third, desalination of brackish and saline groundwater is becoming increasingly common, and will likely increase in the future under predicted drought conditions, climate change, population growth and movement, and changes in well drilling and treatment technologies and costs. As such, limiting protections to groundwater with less than 10,000 TDS mg/L is inadequate.

We recommend adding a definition for a class of protected water which establishes that all waters with potential beneficial uses be protected from injection activity. This class of groundwater must include:

- Aquifers that could supply a private water well, or any other beneficial use, regardless of meeting the federal USDW definition, including the quantity threshold;
- Aquifers with salinity greater than 10,000 TDS mg/L in order to protect aquifers that may be used in conjunction with desalination. While there may not be a scientifically justifiable upper salinity limit, a salinity level that at least protects groundwater currently in use via desalination would be more appropriate than 10,000 TDS mg/L, which is an arbitrary value and not based on actual water use;
- Aquifers that currently supply water for any beneficial use. This would ensure that all water users, including private well owners are protected.

Response to Comment 0019-9: NOT ACCEPTED. Establishing a new regulatory class of groundwater is outside the scope of this rulemaking action. As discussed in the Initial Statement of Reasons, the proposed regulations continue and clarify the Division’s practice of identifying “freshwater” (defined as containing 3,000 mg/L or less TDS, consistent with SWRCB policy) and USDW (as defined by federal law) as categorical thresholds of regulatory significance. However, consistent with the overarching performance standard of confinement of injected fluids, the proposed regulations also include protections applicable to situations where there is existing beneficial use water containing 10,000 mg/L or more TDS. As part of the project data requirements for every underground injection project, proposed section 1724.7, subdivision (a), requires identification and evaluation of potential impacts on all water supply wells within the area of review. Proposed section 1724.10, subdivision (e), requires operators to provide additional yearly reporting of injection fluid information that occurs in proximity

<p><i>to a water supply well. As defined in proposed section 1720.1, subdivision (s), a “water supply well” means a well that provides water for domestic, municipal, or irrigation purposes, without regard to TDS or other specific quality metrics.</i></p>
<p>0018-7 1720.1(n)(2): Aquitards often have higher porosity than aquifers, at least prior to consolidation due to groundwater pumping. Consequently, they have a greater quantity of water per volume of matrix than due aquifers. I suggest changing the phrase “<i>Contains a sufficient quantity of groundwater</i>” to “<i>Can be produced at a rate sufficient.</i>”</p>
<p><i>Response to Comment 0018-7 NOT ACCEPTED. The definition of “USDW” in the proposed regulations is closely modeled on the federal definition of the same term. The Division believes that maintaining this harmony with the federal definition provides benefits of clarity and consistency that are particularly important within the cooperative federalism context under which the Division and the US EPA implement the SDWA.</i></p>
<p>0018-8 1720.1(n)(2): This definition leaves out domestic wells serving one to a few residences. I suggest changing “<i>supply a public water system</i>” to “<i>supply a single residence.</i>”</p>
<p><i>Response to Comment 0018-8: NOT ACCEPTED. The definition of “USDW” in the proposed regulations is closely modeled on the federal definition of the same term. The Division believes that maintaining this harmony with the federal definition provides benefits of clarity and consistency that are particularly important within the cooperative federalism context under which the Division and the US EPA implement the SDWA. Separate from the definition of USDW, the proposed regulations do include requirements to identify individual water supply wells as part of the mandatory area of review for all underground injection projects, and to report additional injection fluid information depending on proximity to a water supply well. See proposed sections 1724.7, subdivision (a) and 1724.10, subdivision (e). As defined in proposed section 1720.1, subdivision (s), a “water supply well” means a well that provides water for domestic, municipal, or irrigation purposes, without regard to the total quantity of the source.</i></p>
<p>0002-10 1720.1(p) “Water supply well”: Commenter recommends amending this definition to remove industrial wells from the definition of a water supply well.</p>
<p>0007-3 1720.1(p): Add language “<i>...does not include beneficial use of water from a DOGGR classified Water Supply (WS) well or from an oil and/or gas production facility...</i>” The Mount Poso Power Plant is supplied water from a DOGGR classified WS well or from the West Mount Poso oil processing plant. The DOGGR classified WS wells provide water from the USDW exempted Vedder formation. This section must allow for the continued operation of facilities and other operations that have a similar beneficial use.</p>
<p><i>Response to Comments 0002-10 and 0007-3: ACCEPTED IN PART. The definition of “water supply well” at proposed section 1720.1, subdivision (s), is intended to include wells that provide water for a broad range of beneficial uses, including industrial uses. However, the Division agrees that wells used to supply water for certain oil and gas operations present a different set of regulatory concerns for the Division than do those intended to be captured by the definition of “water supply well.” Accordingly,</i></p>

the Division has added to the definition of “water supply well” a specific exception for wells drilled within or adjacent to an oil or gas pool for the purpose of obtaining water to be used in production stimulation or repressuring operations. A well within that exception is a “water source well,” as defined at proposed section 1720.1, subdivision (r).

1724.6 Approval of Underground Injection Projects

0002-5

1724.6: The proposed regulation still fails to outline an established administrative process for the Division’s review of new and existing UIC projects. Commenter believes clear standards for review and appeals should be established to better inform operators and the process. In the case of existing UIC projects, it is especially critical that new requirements and delayed review does not halt existing production operations.

***Response to Comment 0002-5: NOT ACCEPTED.** The proposed regulations establish an updated framework of specific requirements and performance standards applicable to approval and operation of underground injection projects in California. Existing statutes and regulations do not provide for an administrative-level appeal from the Division’s processes for approval of proposed well operations and underground injection projects, or from the Division’s processes for routine compliance review of the same. The Division believes dialogue between its staff and members of the regulated community provides the first and best method for ensuring timely and effective evaluation of well operations and underground injection projects. Where life, health, property, natural resources, or the environment may be threatened, the Division must have the ability to modify, suspend, or rescind approval to mitigate that threat. If an operator’s project approval is affected by a Division order, then the operator’s rights to appeal are found in PRC sections 3350 to 3359, which apply to all Division orders issued to operators of injection wells.*

0017-1, 0005-1

1724.6: It has been communicated that a scheduled review of the Division-State Water Resources Control Board (SWRCB) Memorandum of Agreement (MOA) will define UIC Project Approval Timelines for reviewing parties to reach each milestone of the UIC approval process. Without timelines, UIC approvals have languished, unnecessarily delaying investments and facility upgrades and worsening California's dependence on imported energy from places that don't apply our state's leading safety, labor, human rights and environmental standards. If the MOA review process will not define these timelines soon, Commenter requests that the Division specify timelines in the UIC regulations.

***Response to Comments 0017-1 and 0005-1: NOT ACCEPTED.** Committing to regulation a set of predetermined timelines for the Division to complete review and approval of underground injection projects is not within the contemplated scope of the proposed regulations. Evaluation of injection wells and subsurface features is a complex endeavor, with many case-by-case variables to consider. The Division undertakes approval and review of underground injection projects with diligence, but variations in the time necessary to evaluate each project are inherent to the nature of the exercise. It is Division practice to maintain close contact with operators regarding the status of pending reviews and approvals affecting their existing or proposed underground injection projects.*

0019-11

1724.6: Granting or modifying of a project approval letter should be preceded by a 30-day public comment period and public hearing. Currently the public has no opportunity to weigh in on injection projects.

Response to Comment 0019-11: NOT ACCEPTED. *Consistent with the Division’s April 1981 “Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act,” and the subsequent Primacy Agreement between the Division and the US EPA, it is Division policy and practice to publish in a regionally available newspaper a notice inviting public comment regarding each request for approval of a new underground injection project or for approval of substantial changes to an existing underground injection project. The Division does not see a need to codify this policy within the proposed regulations. Other forms of notice and opportunities for comment regarding underground injection projects also may arise in connection with applicable local agency approvals, and any applicable environmental review procedures undertaken by the appropriate lead agency.*

0019-13

1724.6: All PALs must be accompanied by a groundwater monitoring plan, or an exemption letter, granted by the State Water Board. We recommend following the requirements of Senate Bill 4 (Pavley) which describes groundwater monitoring requirements for well stimulation treatments. The SB 4 groundwater monitoring scheme allows for flexibility for the State Board to grant exemptions, to determine coverage under regional monitoring plans, or to require well specific monitoring plans. A parallel scheme for injection projects would close a major monitoring gap and complement the ongoing efforts to better understand groundwater quality in and around oil fields and the potential impacts of oil development on groundwater.

Response to Comment 0019-13: NOT ACCEPTED. *Evaluation of whether groundwater monitoring is necessary for any given underground injection project involves coordinated input from the Division, the SWRCB, and the appropriate regional water quality control board. Where necessary to ensure appropriate protection of groundwater resources, the proposed regulations contemplate that groundwater monitoring will be required as part of the supporting project data to be filed with the Division. See proposed section 1724.7, subdivision (a)(3)(E). Conversely, if an underground injection project is situated in a location where groundwater resources are not proximal, groundwater monitoring may be unnecessary. The proposed regulations preserve and support the ability of these agencies to exercise independent but coordinated authority in tailoring monitoring requirements to meet situation-specific considerations. The Division does not agree that adding a more prescriptive groundwater monitoring requirement to the proposed regulations would be an improvement.*

0007-5

1724.6(c): To avoid confusion regarding the current PAL requirements only an addendum or revised PAL should be issued. Commenter supports issuing a revised PAL to avoid potential confusion regarding current PAL requirements.

Response to Comment 0007-5: NOT ACCEPTED. *The reference in proposed section 1724.6, subdivision (c), to the use of an addendum to modify a project approval letter reflects the reality that in some situations it may be more practical to update a portion of a project approval letter rather than to issue a new project approval letter. For example, this might be the case when tracking changes in which*

specific injection wells within an underground injection project are approved for injection at any given time, or in documenting changes to a required monitoring program.

0008-3

1724.6(d) Commenter supports the Division's proposal to set a fixed frequency for performing Project Approval Letter reviews. However, to be consistent with the Division's Manual of Instructions and directives to the district offices, such reviews should be performed yearly. Results of these reviews should be made publicly available on the Division website.

0019-14

1724.6(d): Project review should occur on a not less than annual basis.

Response to Comments 0008-3 and 0019-14: NOT ACCEPTED. *Completing a review of an underground injection project often takes between three and six months, sometimes longer. Given the variations of size and complexity that exist among underground injection projects, the number of underground injection projects in the state, and practical realities of staff resource limitations, the Division believes that "periodically, but not less than once every three years" is an appropriate regulatory benchmark for routine Division review. This benchmark provides flexibility for the Division to prioritize its resources; it contemplates reviewing some projects sooner or more frequently than others as circumstances warrant, while still providing a clear expectation of review by no later than a regular schedule.*

0004-6

1724.6(g): For new projects, two years is too short of a period to have the PAL expire. Commenter suggests adding an extended period for new projects to four years and an optional extension upon request of two additional years. We are trying to avoid a redundant review in case of extended development cycles. The industry has downturns and needs flexibility once a project is approved in terms of the timing to build out the project.

0002-6

1724.6(g): The proposed regulation continues to set an arbitrary expiration timeframe for Project Approval Letters for non-active projects. Given the extensive resources and energy committed to developing these projects, the uncertainty of the market and the arduous review already completed by DOGGR and the Water Board, Project Approval Letters should not be allowed to expire after such a short time frame. *"Project Approval Letters shall ~~expire~~ be suspended, and be deemed null and void... Division approval ~~a new approval process and Project Approval Letter...~~ under previously approved Project Approval Letter conditions."*

0014-14, 0017-2

1724.6(g): Commenter believes this provision is overly restrictive and places an unnecessary burden on operators, without improving the safe execution of the UIC project. The 24-month time limit also fails to take into account market and economic factors or other operational considerations that may necessitate temporary suspensions of operations, contrary to the rights of mineral owners and operators. So long as the operator continues to ensure the mechanical integrity of the well, re-permitting should not be required to resume operation. Operators expend significant resources in obtaining UIC permits for the purpose of long-term development of an area. For these reasons, Commenter believes that PALs should remain valid over a period of five years of non-injection. At a minimum, rather than requiring projects go through an entirely new approval process after two years

idle, Commenter believes there should be a process by which an extension can be granted while an expedited “reactivation” review takes place. Accordingly, Commenter recommends that the proposed 24-month expiration on project approval letters for idle injection operations should be extended to 60 months to align with the long-term planning required to successfully operate an oil and gas field, and to avoid revisiting projects that were already extensively reviewed and approved by the Division.

0014-40

1724.6(g): This provision is overly restrictive and places an unnecessary burden on the operator without improving the safe execution of a UIC project. This time limit also fails to take into account market/economic factor or other operational considerations that may necessitate temporary suspensions of operations. So long as the operator continues to ensure the mechanical integrity of the well, re-permitting should not be required to resume operation. Rather than requiring projects to go through an entirely new approval process after two years idle, there should be a process by which an extension can be granted while an expedited “reactivation” review takes place.

0019-16

1724.6(g): Commenter supports this section, yet urges a change to twelve months without injection to cancel an approval.

0007-6

1724.6(g): The UIC and Idle Well rules should be synchronized to support each other. If an idle well passes the required idle well testing that well should not have an expiration date due to a PAL expiration date. A wellbore has value to the operator, DOGGR and California citizens. The economics for a field could result in shutting in a project for a period of time and a PAL expiring during that time would result in loss of value to the field and a significant delay returning the field to protection. This is a significant impact to operators and mineral owners.

Response to Comments 0002-6, 0004-6, 0007-6, 0014-14, 0014-40, 0017-2, and 0019-16: ACCEPTED IN PART. *Proposed section 1724.6, subdivision (g), has been deleted. The proposed regulations no longer prescribe as a predetermined regulatory consequence the expiration of a PAL after 24 months without injection, requiring the operator to then obtain a new PAL in order to resume injection. Instead, the proposed regulations now address project-level inactivity with several functionally similar but more flexible provisions focused on well-specific considerations.*

Proposed section 1724.6, subdivision (b), has been amended to indicate that the Division may specify within a PAL a limited approval duration for an underground injection project. Additionally, under proposed section 1724.13, subdivisions (a)(8) and (b), unless the operator has requested and received Division approval for the well to remain approved for injection while idle, an operator is required to cease injection into an injection well when it becomes idle, and not resume injection without subsequent written permission from the Division. Proposed section 1724.6, subdivisions (d) and (e), make clear that obtaining permission from the Division to resume injection that has been suspended pursuant to proposed section 1724.13 may involve review and revision of PAL terms and conditions.

1724.7 Project Data Requirements

0002-4

1724.7: The proposed regulation places a significant burden on operators to supply data. In many cases, data is either unnecessary or already provided to DOGGR through existing permits or as a result of extensive data requests related to Aquifer Exemptions throughout California. In either case, UIC program goals of resource and environmental protection are already achieved. This information should not have to be provided again.

0017-12

1724.7: Some of the data requested in the draft regulations is excessive and is typically already provided during the Aquifer Exemption (AE) application process. To avoid unnecessary or duplicative work, Commenter proposes that when information has already been provided to the Division (i.e., in the form of an aquifer exemption application), operators may reference those applications and subsequent approvals. Commenter believes that sealing mechanisms and confinement are addressed in the Aquifer Exemption process and operators and Division and Water Board staff should not have to review those same issues again when submitting UIC applications. Instead, UIC regulations should address confinement on a wellbore level only. Reviewing regional confinement within the UIC application rather than the aquifer exemption process will inordinately delay approval and unnecessarily complicate UIC permitting and investment in existing fields, hurting California energy production and jobs.

Response to Comments 0002-4 and 0017-12: NOT ACCEPTED. The additional data proposed section 1724.7 requires operators to collect and file with the Division are necessary to ensure that there exists in every instance an adequate, standardized body of information by which the Division can evaluate for regulatory compliance the operation of all underground injection projects. In broad terms, the data required for each underground injection project consist of an engineering study, a geologic study, and an injection plan. A detailed discussion of each specific data requirement and the rationale for it may be found in the Initial Statement of Reasons.

In some cases, perhaps many, operators may be able to use existing data sources to achieve compliance with various requirements of proposed section 1724.7. To facilitate timely and efficient execution of the Division's regulatory mission, however, it is essential that a complete set of the required data be filed in association with its respective underground injection project. The Division believes concerns regarding any potentially unnecessary duplication in filing for a specific underground injection project are appropriately addressed on a case-by-case basis.

0013-12

1724.7(a): This section requires that operators submit data that demonstrate "to DOGGR's satisfaction that fluid will be confined to the approved injection zone and that the underground injection project will not cause damage to life, health, property, or natural resources" and, further, "to DOGGR's satisfaction that injection fluid will not migrate out of the approved injection zone through another well, geologic structure, fault, fracture, or fissure, hole-in-casing, or other pathway...." The reliance on DOGGR's judgment is improper where DOGGR has shown in the past that it has regularly approved injections that violate state and federal law. The subsection should delete

<p>the italicized provision so that operators must demonstrate fluid containment objectively rather than through DOGGR’s subjective lens.</p>
<p>Response to Comment 0013-12: NOT ACCEPTED. <i>Geology is in many respects an interpretative science. The language in proposed section 1724.7, subdivision (a), regarding data demonstrating confinement of injected fluid “to the Division’s satisfaction” reflects the reality that geologic interpretation will guide the Division’s determination of compliance with the performance standard. The authority to make that determination has been entrusted to the Division by the legislature, as reflected in PRC section 3000 et seq., and particularly PRC sections 3013 and 3106.</i></p>
<p>0018-52</p>
<p>1724.7(a): Minor text edits, “...satisfaction that injected ion fluid...accurately reflective of the project...”</p>
<p>Response to Comment 0018-52: ACCEPTED. <i>Text edits made as recommended.</i></p>
<p>0014-41</p>
<p>1724.7(a): The phrase “account for all changes to the setting and operation of the project” is unclear. If the purpose of this is to require the operator to notify DOGGR of changes to the project over the operating life, Commenter strongly recommends that the regulations identify the specific types of changes that are subject to the reporting requirement. As drafted, the regulations are subject to wide interpretation and will result in significant uncertainty as to the types of changes that are reported to, and may require further action by, DOGGR. Absent specification of the types of changes subject to notification, Commenter suggests that the regulations be revised to simply delete this provision. So long as the Operator is complying with the conditions of the Project Approval Letter, minor changes should be of no consequence.</p>
<p>Response to Comment 0014-41: ACCEPTED. <i>The language has been deleted as suggested.</i></p>
<p>0002-12</p>
<p>1724.7(a) and (a)(3)(E): Commenter recommends removing language related to confinement to approved zones and replacing with a requirement to show that fluid will <u>not migrate to a USDW zone.</u></p>
<p>Response to Comment 0002-12: NOT ACCEPTED. <i>PRC section 3106 sets a broad regulatory mission for the Division that includes, but also goes beyond, ensuring injected fluids do not infiltrate and damage a USDW. The project data requirements of proposed section 1724.7 are appropriately tailored to the breadth of the Division’s statutory directive: “prevent, as far as possible, damage to life, health, property, and natural resources.”</i></p>
<p>0018-9</p>
<p>1724.7(a)(1)(B): Commenter suggests clarifying the distinction between “all wells” in this subdivision and the reference to “all water supply wells” in the following subdivision by qualifying the phrase “all wells” with “<u>related to oil and gas production,</u>” and by explicitly mentioning abandoned.</p>
<p>Response to Comment 0018-9: NOT ACCEPTED. <i>The Division believes the existing language is sufficiently clear.</i></p>

0014-44

1724.7(a)(1)(B)(i): Commenter does not believe it should be necessary to map wells located outside the area of review. At a minimum, if “adjacent” wells must be included on the map, DOGGR must define “adjacent” for purposes of this requirement (e.g., 10 feet, 50 feet, 100 feet?) Requirements for showing the well status and indicating the interval penetrating the injection zone are more appropriate for a list not a map. Commenter suggests these elements be added to subdivision (a)(7) below. Further, directional surveys for vertical wells may not be available, and it may be difficult to map the injection interval along a deviated path. It is not possible at the outset of the project to accurately map the complete arc of every well.

***Response to Comment 0014-44: NOT ACCEPTED:** Consistent with similar federal regulations, the proposed regulations contemplate case-by-case, project-specific determination of AOR boundaries, as appropriate to meet a performance standard: that the area of review be at least as broad as the area of influence. Adjacent wells include wells with a wellhead located outside the boundary of an AOR but a wellbore which has deviated from vertical and potentially entered the AOR below ground. Where the wellbore path is known to come near the boundary, it will need to be included. Knowing nearby wellbore pathways is an important component for evaluating confinement of injected fluid. The Division disagrees that mapping the arc of wells near the boundaries of an AOR will be impossible or impractical for operators in most situations.*

0004-7

1724.7(a)(1)(C)(ii): This section has a requirement to disclose the ownership of water supply wells. Our understanding is that in the past we’ve been asked to redact ownership information. We would like to clarify whether this has changed and is legal for a producer to share this information in a public document.

***Response to Comment 0004-7: ACCEPTED.** The requirement to include ownership information for water supply wells has been removed.*

0014-17

1724.7(a)(1)(C)(iii): This requirement imposes a significant burden on operators to provide the wellbore diagrams even though the Division has stated on many occasions that it now has access to wellbore diagrams through the WellStar database. In many instances, the Division may have sufficient information in the database to prepare necessary casing diagrams itself. In such cases, operators should not be required to provide that information. Commenter recommends that this section be revised to specify that graphical casing diagrams or flat file data sets will not be required if this data is already available to the Division through its digital database.

***Response to Comment 0014-17: NOT ACCEPTED.** Casing diagrams are an integral part of Division oversight. In many cases, sufficient digital data for creation of casing diagrams is not currently available in well files. Operators have the option of submitting graphical casing diagrams or submitting the data via a flat file. The Division believes concerns regarding any potentially unnecessary duplication in filing for a specific underground injection project are appropriately addressed on a case-by-case basis.*

0014-45

1724.7(a)(1)(C)(iii): Casing diagrams will not always demonstrate that the wells will not be a potential conduit. DOGGR must acknowledge this fact. The opportunity to provide alternate data to

demonstrate that fluid will remain confined to the zone and will not cause damage to life, health, property, or natural resources is provided by section 1724.7(d). Additional revisions are suggested to simplify the language of the regulation, including the removal of “..and that are completed in or penetrating the same or a deeper zone...including directionally drilled wells...”

Response to Comment 0014-45: NOT ACCEPTED. *Casing diagrams are not a stand-alone method for demonstrating confinement of injected fluid. Evaluation of casing diagrams is one component of the engineering study portion of the project data requirements, and a part of the comprehensive data package the Division utilizes to carry out its regulatory mission. The language recommended for removal is necessary to ensure that all wells which may affect the zone are included (penetrating and completed, the injection zone or a deeper zone). The potential option to provide alternate data as described in proposed section 1724.7, subdivision (e), applies to casing diagrams.*

0014-47

1724.7(a)(1)(D): Well drilling and plugging and abandonment plan submitted as part of an application must be understood to be preliminary. Operators cannot be limited to pattern designs, well locations, or well counts estimated prior to the acquisition of actual project data through drilling of new wells and operational experience.

Response to Comment 0014-47: NOT ACCEPTED. *It is essential for effective regulation that operators provide the Division with updated project data as circumstances change or new information becomes available. As specified in proposed section 1724.7, subdivision (a): “the operator is responsible for ensuring that the data are current and accurately reflective of the project setting and operation throughout the operating life of the project.” The proposed regulations do not require clairvoyance, but if the plans for a well drilling and plugging and abandonment program change, the proposed regulations will require the operator to provide the Division with the most current, updated plan information promptly.*

0014-46

1724.7(a)(1)(F): The requirement to identify and provide various information about all wells within the area of review that do not penetrate the injection zone of the underground injection project should be limited to oil and/or gas wells, not other types of wells. Also, wells located on offset operator acreage should be excluded from this requirement.

Response to Comment 0014-46: NOT ACCEPTED. *The provisions referenced by the commenter, addressing evaluation of wells within an area of review, have been relocated under proposed section 1724.8, subdivision (a)(1). In order to be effective for the purposes of identifying potential conducts for migration of injected fluid, and other potential risks, it is important that all wells within an area of review be evaluated. There is no reason to limit the evaluation only to oil and gas wells, or to exclude wells solely because they are operated by an offset operator.*

0014-18

1724.7(a)(2)(A): This requirement presents significant concerns, as information on residual oil and gas saturations is highly proprietary data relating to reserve valuations. Additionally, this requirement would provide no value for the purpose for which it is being requested, since original and residual saturations are unrelated to containment and ability to safely operate a UIC project. Additionally, establishing “original saturations” on a PAL-specific basis is impossible to prove with any degree of accuracy, especially in instances where a single oilfield is covered by multiple PALs. Accordingly,

<p>Commenter recommends that the requirement to provide information on “original and residual oil, gas, and water saturations” be deleted from this section.</p>
<p>0014-42 1724.7(a)(2)(A): Information on residual oil and gas saturations is highly proprietary data relating to reserve valuations and should be deleted as a data requirement. Clarification is also needed as to whether information pertaining to the fracture gradient of the injected zone must be submitted.</p>
<p><i>Response to Comments 0014-18 and 0014-42: NOT ACCEPTED. The requirement for operators to provide original and residual saturations as part of the data supporting an underground injection project is a requirement present in existing regulations. The proposed regulations do not materially change this requirement; they only reorder its section numbering. Original and residual saturation data provide vital information to the Division for its oversight of reservoir management, including information about volume produced and voidage. Existing law provides procedures by which operators may preserve the confidentiality of certain records filed with the Division, including records containing experimental or interpretative data. See PRC section 3234 and CCR title 14, section 1997 et seq.</i></p>
<p>0014-43 1724.7(a)(2)(B) Commenter suggests that the requirement to provide “water quality” data as part of the reservoir fluid data for each injection zone be changed to “current water quality.” The commenter believes water quality data collected at the time the project is proposed are most useful, and that in many cases it would be difficult to obtain truly “native” water quality data from areas that have been influenced by injection for decades. Commenter suggests adding specified test method for the requirement to provide data regarding the “presence and concentrations of non-hydrocarbon components in the associated gas” as part of the reservoir fluid data for each injection zone.</p>
<p><i>Response to Comment 0014-43: ACCEPTED IN PART: Samples of reservoir liquid that are accurately representative of the reservoir fluid at the injection zone in its native state, prior to any injection, are more useful for analysis of injection influence and fluid confinement. However, the Division agrees that obtaining samples of reservoir liquid in a native state may not be feasible in all cases. Proposed section 1724.7.2, subdivision (c), has been added to clarify that a sample of the reservoir liquid from the injection zone itself in its native condition is required only “if feasible.” If it is not feasible to collect a sample of the reservoir liquid from the injection zone in its native state, an operator may instead comply with the requirement by analyzing a sample collected from an analogous reservoir that has not already received injection fluid.</i></p> <p><i>The Division does not believe it is necessary to prescribe a gas composition testing procedure for purposes of this data requirement. Operators may select any testing methodology that is capable of accurately analyzing the composition.</i></p>
<p>0014-47 1724.7(a)(2)(C): Structural contour maps by definition should contain controlling features such as faults and other lateral controls -- to specifically call for these features is redundant. In addition, requiring a cross section including three wells may not be possible in greenfield projects (i.e., where</p>

there are no existing wells in a new project area) or where injection wells are located at the perimeters of the project area. Exceptions should be made where an injection well is not available. Representative cross sections should be sufficient.

Response to Comment 0014-47: NOT ACCEPTED. Although commenter may consider faults and other lateral containment features to be implicit elements of a structural contour map, the Division felt it was important to delineate the specific features that must, at minimum, be included. If it is not possible to generate the data required, an operator may seek Division approval for an alternative data demonstration under proposed section 1724.7, subdivision (e).

0018-53

1724.7(a)(2)(F): Minor text edit, "...below the deepest production or injection zone, whichever is deeper (if not already shown on the cross section) identifying..."

Response to Comment 0018-53: ACCEPTED. Text edits have been made as recommended.

0019-17

1724.7(a)(3)(A): All purposes must be disclosed. For example, if a project has the dual purpose of enhancing oil production and disposing of produced water, then both purposes must be specified. Recommended edits: "Statement of primary purposes of the project."

Response to Comment 0019-17: NOT ACCEPTED. This section is part of the injection plan, which is focused on the primary purpose of the underground injection project. It is not intended to include all of the operator's activities.

0014-52

1724.7(a)(3)(D): The regulation should be revised to place a reasonable limitation on how much forward-looking data is required. It is not possible at the outset of a project to identify all future production or injection wells.

Response to Comment 0014-52: ACCEPTED. This comment refers to language in a pre-rulemaking draft version of the injection plan project data requirements portion of the proposed regulations, which in pertinent part called for identification of "all production wells that are intended to be affected by the underground injection project." The corresponding portion of the proposed regulations, proposed section 1724.7, subdivision (a)(3)(D), has been revised and now requires, in pertinent part, identification of "any planned wells to the extent known." It is essential for effective regulation that operators provide the Division with updated project data as circumstances change or new information becomes available. As specified in proposed section 1724.7, subdivision (a): "the operator is responsible for ensuring that the data are current and accurately reflective of the project setting and operation throughout the operating life of the project."

0019-18

1724.7(a)(3)(D): Identification of wells should include water source wells "within 1 mile of the injection zone."

Response to Comment 0019-18: NOT ACCEPTED. The purpose of proposed section 1724.7, subdivision (a)(3)(D), is to establish a requirement that the injection plan project data component supporting an underground injection project identify the wells that will be operated as part of the project. The injection plan is not intended to provide an identification of wells that are not operated as part of the underground injection project. Identification of all nearby wells is required as part of the engineering study project data component, under proposed section 1724.7, subdivision (a)(1).

0014-48

1724.7(a)(3)(E): Groundwater monitoring programs are typically developed by an operator pursuant to other regulatory programs, separate from the UIC project approval process. If groundwater monitoring is not required by some other regulatory program (e.g. as part of SB4), any groundwater monitoring should be at the operator's discretion. Where groundwater monitoring is conducted at the operator's discretion, any requirement to share monitoring results with the State Board of Regional Board should be done pursuant to the terms of a PAL, and not referenced as a condition in the UIC regulations.

Response to Comment 0014-48: NOT ACCEPTED. The proposed regulations do not prescribe a groundwater monitoring requirement for underground injection projects. Proposed section 1724.7, subdivision (a)(3)(E), recognizes that the SWRCB and regional water quality control boards may require groundwater monitoring as a condition of approval for an underground injection project. Where groundwater monitoring is required in relation to an underground injection project, it will be incorporated as a term or condition of the PAL.

0008-6, 0019-2

1724.7(a)(3)(E): Groundwater monitoring should be mandatory for all UIC projects. The primary goal of the UIC program is to ensure that underground injection does not endanger drinking water. Except in obvious cases of visible blowouts or severe contamination, active monitoring is required to detect contamination related to injection, which is critical to achieving the UIC Program's goal. Neither federal Class II regulations nor existing California state regulations, however, require comprehensive, ongoing monitoring of wells or of USDWs that may be impacted by injection operations. Like the Division's rules for well stimulation, project-specific or regional groundwater monitoring should be required for all UIC projects. Recommended text: "The monitoring system must be approved by the State Water Resources Control Board or Regional Water Quality Control Board, and if it does not include groundwater monitoring, the operator must obtain an exemption from the State or Regional Board based on a demonstration that groundwater monitoring is not appropriate due to the lack of groundwater with potential beneficial uses, or that the injection project is adequately covered by a regional monitoring plan."

Response to Comments 0008-6 and 0019-2: NOT ACCEPTED. Evaluation of whether groundwater monitoring is necessary for any given underground injection project involves coordinated input from the Division, the SWRCB, and the appropriate regional water quality control board. Where necessary to ensure appropriate protection of groundwater resources, the proposed regulations contemplate that groundwater monitoring will be required as part of the supporting project data to be filed with the Division. See proposed section 1724.7, subdivision (a)(3)(E). Conversely, if an underground injection project is situated in a location where groundwater resources are not proximal, groundwater monitoring may be unnecessary. The proposed regulations preserve and support the ability of these agencies to exercise independent but coordinated authority in tailoring monitoring requirements to meet situation-specific considerations. The Division does not agree that adding a more prescriptive groundwater monitoring requirement to the proposed regulations would be an improvement.

0014-49

1724.7(a)(4): Requiring a step rate test for every well in a UIC project is an unreasonable requirement. A step rate test from a representative well should be sufficient, as data from the test can be extrapolated to other wells. In attempting to obtain UIC approvals, operators may not have access to facilities to provide fluid for injection. This would require expensive, individual well testing using portable skids and trucking fluids to run the tests, increasing operational and safety risk. It is not feasible to construct facilities in advance and then have the facilities sit idle pending DOGGR's approval of the UIC project. Representative data should be able to be used for the project area.

Response to Comment 0014-49: ACCEPTED. This comment refers to language in a pre-rulemaking draft version of the project data requirements portion of the proposed regulations, which has since been deleted and substantively supplanted by maximum allowable surface injection pressure requirements in proposed section 1724.10.3. Proposed section 1724.10.3, subdivision (c), provides that operators may, with Division approval, use an estimated baseline fracture gradient to determine the maximum allowable surface injection pressure for all wells within an injection area. To be approved, an estimated baseline fracture gradient must be supported by representative step-rate test or other geologic data demonstrating to the Division's satisfaction that the estimated baseline fracture gradient is lower than the actual fracture gradient that would be encountered anywhere in the area injection zone where the estimated baseline fracture gradient will be used.

0007-7

1724.7(a)(5): Commenter suggests that the Division change the existing requirement that each underground injection project be supported by copies of letters of notification sent to offset operators by only requiring copies of letters of notification sent to the offset operators of wells located within the AOR for the underground injection project.

Response to Comment 0007-7: NOT ACCEPTED. Existing regulations require operators to provide the Division with copies of letters of notification sent to offset operators. The proposed regulations alter the section numbering of this requirement but do not materially change it. Wells operated by an offset operator generally would not be within the AOR because the injection pressures for the underground injection project would be adjusted by the PAL requirements to keep influence from traveling across lease lines, wherever possible. Notification to offset operators is an important precautionary measure to help ensure that neighboring operations do not interfere with one another or interact in other problematic ways.

0008-4

1724.7(a)(5): Commenter requests that the Division clarify what information is required to be contained in the "letters of notification" and require notice to be given at least 30 days before commencement of injection and include proof of service.

0019-20

1724.7(a)(5): Add: "Copies of notification letter sent to all property owners informing of injection activities and potentially compromise the ability of land owners to drill wells in the future."

Response to Comments 0008-4 and 0019-20: NOT ACCEPTED. Existing regulations require operators to provide the Division with copies of letters of notification sent to offset operators. The proposed regulations alter the section numbering of this requirement but do not materially change it. The Division does not see a present need to establish more prescriptive regulatory requirements for offset

operator notification letters. Consistent with the Division's April 1981 "Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act," and the subsequent Primacy Agreement between the Division and the US EPA, it is Division policy and practice to publish in a regionally available newspaper a notice inviting public comment regarding each request for approval of a new underground injection project or for approval of substantial changes to an existing underground injection project. Other forms of notice and opportunities for comment regarding underground injection projects also may arise in connection with applicable local agency approvals, and any applicable environmental review procedures undertaken by the appropriate lead agency.

0014-50

Commenter believes the discussion draft version of proposed section 1724.7, subdivision (a)(6), regarding project data requirements, is too vague, particularly as to the interpretation of "large," "unusual," and "hazardous." Commenter suggests the section needs to be revised to define the specific circumstances under which additional data can be required and to state the purpose for the additional data requested. Commenter recommends making the following additions (underlined) and deletions (strikethrough):

"Other data as required, to the extent available, for large ~~or~~ unusual, ~~or hazardous~~ projects, for unusual or complex structures, or for critical wells. ~~Examples of such data are: isogor maps, water-oil ratio maps, isobar maps, 3-D maps, computer geologic models, equipment diagrams, and safety programs.~~"

0014-53

1724.7(a)(6): Commenter believes the Division's discretionary authority to require additional project data is too broad, and may result in unfair delays of in the approval of proposed underground injection projects. Commenter suggests the addition of the following sentence as a limitation on the Division's authority to require an operator to provide, as project data, any additional data it judges to be pertinent and necessary of evaluation of an underground injection project: "Any request for additional data pursuant to this paragraph shall be in writing, signed by the deputy supervisor for the district, and shall describe with specificity the particular data that are requested, the purpose of the additional data, and how the data are necessary to a decision to approve the project application."

***Response to Comments 0014-50 and 0014-53: ACCEPTED IN PART.** This comment refers to language in a pre-rulemaking draft version of proposed section 1724.7, subdivision (a)(6). The Division agrees that the qualifications regarding large, unusual, and hazardous projects were unnecessary. These have been deleted. The Division's existing authority to require other, additional, and flexibly specified data on a case-by case basis as necessary to evaluate each underground injection project's conformance with applicable requirements is essential to the Division's ability to carry out its regulatory mission in timely and effective manner. As modified, the pertinent portion of proposed section 1724.7, subdivision (a)(6) now reads: "Any other data that, in the judgment of the Division, are pertinent and necessary for the proper evaluation of the underground injection project." The Division does not agree that it would be helpful to delete the examples of data that might be required.*

0014-51

1724.7(a)(6): Language also needs to be added that will preclude public access to proprietary data that may be submitted to the regulatory agency as part of an application. 3D maps and computer

<p>models are typically proprietary and should not be required to be submitted unless it is established at the outset that the information will be protected from disclosure. Commenter recommends that specific types of data not be referenced in the regulations, and that the types of and need for additional data be determined on a project-specific basis, based on discussion between the operator and DOGGR staff.</p>
<p>Response to Comment 0014-51: NOT ACCEPTED. <i>Project data necessary for evaluation of underground injection projects may in some instances include records that are, or could be, confidential. The potential confidential nature of such records is not a reason to avoid referencing them in regulation as examples. Existing law provides procedures by which operators may preserve the confidentiality of certain records filed with the Division, including records containing experimental or interpretative data. See PRC section 3234 and CCR title 14, section 1997 et seq.</i></p>
<p>0018-10 1724.7(a)(6): Commenter is not aware of a class of work products referred to as 3-D maps. Perhaps 3-D models?</p>
<p>Response to Comment 0018-10: ACCEPTED. <i>The text has been modified to refer to three-dimensional geologic models.</i></p>
<p>0018-54 1724.7(a)(6): Minor text edit, "...<u>isochore</u> maps..."</p>
<p>Response to Comment 0018-54: NOT ACCEPTED. <i>This recommended edit is incorrect given the context of the section. An isochore map would show thickness, while an isogor shows oil to gas ratios.</i></p>
<p>0007-8 1724.7(b): Require only "<u>technical</u>" data for a new injection well.</p>
<p>Response to Comment 0007-8: NOT ACCEPTED. <i>The Division is interested in any and all required data about a new injection well. A limitation to "technical" data is not needed; any and all data gathered will be considered.</i></p>
<p>0014-54 1724.7(b): As drafted, this section infers that the entire PAL data set needs to be updated each time a single well is added. New data submittals should be limited to the well that is being added.</p>
<p>0019-21 1724.7(b): Add: "<u>The addition of a new well to an injection project shall not occur without an updated PAL from the Division.</u>"</p>
<p>Response to Comments 00-14-54 and 0019-21: ACCEPTED IN PART. <i>Language has been added to proposed section 1724.7, subdivision (b), clarifying that the addition of an injection well to an underground injection project shall be indicated on a summary list of approved injection wells associated with the underground injection project and referenced accordingly in the PAL.</i></p>
<p>0018-55 1724.7(b): Minor text edits, "When a new injection well...Division with any new data relevant to the addition of the new well and shall...accurate data <u>have</u> has become..."</p>
<p>Response to Comment 0018-55: ACCEPTED. <i>The text has been edited as recommended.</i></p>
<p>0004-8 1724.7.1(b)(3): Please change to the following: "<u>The wellbore path, providing both inclination and azimuth measurements, and measured depth.</u>"</p>

<p>Response to Comment 0004-8: ACCEPTED. <i>The proposed language has been added to the regulation.</i></p>
<p>0014-55 1724.7(c): Commenter seeks clarification of the requirement to submit data in a “digital” format is needed. Comment queries whether a PDF of a map or casing diagram considered “digital.”</p>
<p>Response to Comment 0014-55: NOT ACCEPTED. <i>“Digital” refers to a machine-readable format that can be processed by a computer; it does not include a file that is just an image which cannot be digitized into data. Some PDFs are digital; they were created using a computer and the data in the file remains convertible by the machine into meaningful data. Other PDFs are just a scanned image; these are not digital because the image cannot be reduced to its base coding data. The Division is requiring “digital” data submissions because the data will be entered into a digital database that will use data from the documents to perform processes that assist the Division in the evaluation and oversight of underground injection projects.</i></p>
<p>0019-22 1724.7(c): Add: “...and shall be posted online by the Division within 5 days...”</p>
<p>Response to Comment 0019-22: NOT ACCEPTED. <i>The Division cannot commit to a specified timeframe for posting of data because the data must be fully processed and validated. The posting of incorrect or “bad” data would lead to more confusion on the part of operators and the public; data must be fully vetted before posting.</i></p>
<p>0014-57 1724.7(e): Commenter seeks DOGGR’s confirmation that this subdivision contemplates, and allows operations in diatomite formations above the fracture gradient.</p>
<p>Response to Comment 0014-57: NOT ACCEPTED. <i>Proposed section 1724.7, subdivision (e), does not address injection in diatomite or other specific operations. The proposed regulations in general do contemplate underground injection projects involving diatomite formations, and case-by-case Division allowance for operators to use a maximum allowable surface injection pressure that may be above the fracture gradient. Proposed section 1724.10.3, subdivision (b), addresses the circumstances under which the Division may approve a maximum allowable surface injection pressure higher than the value that otherwise would be prescribed by regulation under proposed section 1724.10.3, subdivision (a).</i></p>
<p>0019-23 1724.7(e): Comment suggests that the option for the Division to accept alternative data in satisfaction of the specified project data requirements be further restricted not only by required operator demonstrations, but by a requirement that the Division document its approval of the alternative demonstration in writing.</p>
<p>Response to Comment 0019-23: NOT ACCEPTED. <i>The Division believes it can determine the appropriate documentation for an alternative data demonstration accepted under proposed section 1724.7, subdivision (e), without committing itself to the prescriptive business process suggested by the commenter.</i></p>
<p>0008-5 1724.7(e)(1): Commenter requests that the Division clarify what constitutes an “unreasonable burden”, how it will verify such claims, and circumstances under which such an exemption from the preceding data requirements would be appropriate.</p>

Response to Comment 0008-5: NOT ACCEPTED. Determination of what constitutes an “unreasonable burden” inherently entails an exercise of case-by-case judgment. Proposed section 1724.7, subdivision (e)(1), is intended to preserve the Division’s existing discretion to flexibly modify project data requirements to meet presently unanticipated circumstances. As reflected in proposed section 1724.7, subdivisions (e)(2) and (e)(3), in addition to the “unreasonable burden” demonstration, the Division will only accept alternative data in satisfaction of the project data requirements of proposed section 1724.7, subdivision (a), when the operator demonstrates the following:

- the alternative data accomplishes the same purpose as the data it would replace;
- the underground injection project as a whole is supported by data demonstrating that injected fluid will be confined to the approved injection zone, conforms to applicable legal requirements, and will not cause damage to life, health, property, or natural resources.

0014-56

Commenter proposed making the following additions (underlined) and deletions (strikethrough) to the text of a pre-rulemaking discussion draft version of the alternative project data option now contain in proposed section 1724.7, subdivision (e):

Where it is infeasible to supply the data specified in subdivision (a), the Division may accept alternative data, provided that the alternative data demonstrate to the Division’s satisfaction that injected fluid will not move out of ~~be confined to~~ the approved zone or zones of injection in a manner that poses a threat to USDWs or other waters with beneficial uses, and that the underground injection project conforms to the requirements of this subchapter and will not cause damage to life, health, property, or natural resources, including hydrocarbon reservoirs. For purposes of this subdivision, “infeasible” means that the data do not currently exist or do not exist in a reasonably accessible format, and that the burdens associated with developing the data, in terms of cost or human resources, outweighs the need for the data.

Commenter believes the additions provide important clarity regarding the meaning of the term “infeasible” as used in this section.

Response to Comment 0014-56: ACCEPTED IN PART. This comment refers to language in a pre-rulemaking draft version of proposed section 1724.7, subdivision (a)(6). The language of proposed section 1724.7, subdivision (a)(6) has been edited to remove the term “infeasible.” Instead, the option to use alternative data will depend on the operator’s ability to demonstrate to the Division’s satisfaction all of the following: 1) it would be an unreasonable burden to provide the data specified, 2) the alternative data accomplishes the same purpose as the data it would replace, and 3) the project is, on whole, supported by data demonstrating that injected fluid will be confined to the approved injection zone, and that the project conforms to the requirements of this subchapter and will not cause damage to life, health, property, or natural resources.

1724.7.1 Casing Diagrams

0014-26, 0014-59

1724.7.1: Many of the regulations are highly prescriptive and impose requirements and data collection efforts that are technically unwarranted and will not “add value” in terms of demonstrating

well integrity. For example, if adopted as drafted, the regulations would require certain information to be included on all casing diagrams which has not previously been required or, in some cases, which cannot be shown on a casing diagram. These requirements would lead to the need to redo thousands of casing diagrams. At DOGGR's request, operators in the state have expended significant resources and worked diligently over the past several years to update or create new casing diagrams as DOGGR seeks to build an accurate and up-to-date database and improve its diagrams would need to be revised again, at significant further expense and without any clear purpose. In Commenter's view, the new information will not aid DOGGR's ability to evaluate and approve UIC projects.

Response to Comments 0014-26 and 0014-59: NOT ACCEPTED. Casing diagrams are an integral part of Division oversight. In many cases, sufficient digital data for creation of casing diagrams is not currently available in well files. Operators have the option of submitting graphical casing diagrams or submitting the data via a flat file. The Division believes concerns regarding any potentially unnecessary duplication in filing for a specific underground injection project are appropriately addressed on a case-by-case basis.

0006-2

1724.7.1: This section is generally comprehensive, but the Division would benefit from collecting three additional pieces of information. The first is the depths of any open hole completions as part of (a)(8). The second is including the confining zone in the reporting required by (a)(14). The third is adding any available cement logs to accompany the cementing information request in (b). This final element will help the Division make determinations about external mechanical integrity prior to permitting injection.

Response to Comment 0006-2: ACCEPTED IN PART. Open hole completions have been added at what is now proposed section 1724.7.1, subdivision (a)(9). A reference to "confining layers" has been added to at what is now proposed section 1724.7.1, subdivision (a)(15). Requirements for cement identification are already included at proposed section 1724.7.1, subdivisions (a)(12) and (a)(13).

0002-13, 0003-1

1724.7.1(a): Operators are required to submit all casing diagrams for wells within their area of review regardless of ownership, operator, and age. While this is a reasonable request for the review of a UIC project, in older fields the current operator may not have some of the specific information being required for wells abandoned by previous operators. Much of the data required by section 1724.7.1 was not previously required for DOGGR submittal, thus current operators may be unable to obtain it. Recommend the addition of language "...to the extent the data can be obtained by the operator" or "if available".

0007-9

1724.7.1(a)(6): Re: sizes, grades, connection type and weights of casing, add "if available." Some wells do not have this information due to prior ownership not providing the data and not being in the DOGGR files.

0007-11

1724.7.1(b)(3): Add language "if available". Some wells do not have this information due to prior ownership not providing the data and not being in the DOGGR files.

Response to Comments 0002-13, 0007-9, 0007-11, and 0003-1: NOT ACCEPTED. Proposed section 1724.7.1 describes the default regulatory requirements for casing diagrams. If casing diagrams or

other project data required by proposed section 1724.7, subdivision (a), cannot be obtained, proposed section 1724.7, subdivision (e), provides a procedure by which an operator may seek Division approval for an alternative data demonstration.

0018-11

1724.7.1(a): Casing diagrams should also be required to have the spud date, completion date, rework date(s), and plugging date(s).

Response to Comment 0018-11: ACCEPTED IN PART. *The date the well was spudded has been added, at what is now proposed section 1724.7.1, subdivision (a)(2). Completion, rework, and plugging dates are all temporary statuses that may later be updated or may be repeated. The Division does not agree that these dates are necessary data to include on a casing diagram. Casing diagrams are focused on permanent features and information.*

0014-58

1724.7.1(a)(4): Commenter recommends the limitation of the requirement to provide the base of freshwater to those situations where water is actually present by adding “where present” to the end of this subsection.

Response to Comment 0014-58: NOT ACCEPTED. *Where there is no base of freshwater, commenter is correct that it cannot be provided on the casing diagram; any data on the casing diagram that does not actually exist will not be required provided that no alternative is needed to confirm that the well will not be a conduit for fluid migration.*

0014-60

1724.7.1(a)(6): Wellbore diagrams are reviewed to confirm isolation. Tubing configuration can vary over the life of a well and changes to do impact isolation evaluation. MIT surveys indicate packer and tubing depth. Commenter recommends the removal of “grades, connection type” and “and tubing”.

Response to Comment 0014-60: ACCEPTED IN PART. *This comment refers back to a pre-rulemaking discussion draft version of the proposed regulations. The requirement for tubing has been removed from what is now proposed section 1724.7.1, subdivision (a)(7), as recommended by commenter. The Division believes information regarding grades, connection type, and weights of casing are necessary; these will still be required.*

0014-61

1724.7.1(a)(8): Reporting casing damage can be highly subjective. Commenter recommends this be limited to physical damage. Language edits recommend removing “physical casing damage” and replacing with “physical damage to the casing”.

Response to Comment 0014-61: NOT ACCEPTED. *What is now proposed section 1727.7.1, subdivision (a)(9), is already limited to physical damage. Commenter’s suggested edits would not substantively alter the type of information called for.*

0018-57

1724.7.1(a)(8): Delete, “...casing damage, ~~and~~ type and extent of junk...”

0018-58

1724.7.1(a)(9): Delete and add, “...regarding ~~associated~~ equipment in the well such as...”

Response to Comments 0018-57 and 0018-58: ACCEPTED. *Text edits made as recommended.*

0014-63

1724.7.1(a)(11) and (12): This level of detail is unnecessary and requires too much reworking of existing diagrams, without adding materially understanding of subsurface conditions. Commenter recommends removal of "...with indication of method of determining".

Response to Comment 0014-63: ACCEPTED. This comment refers back to a pre-rulemaking discussion draft version of the proposed regulations. The language referenced by commenter has been removed from what are now proposed sections 1724.7.1, subdivisions (a)(12) and (a)(13).

0003-2

1724.7.1(a)(14): UIC regulations are designed to ensure injection fluid is confined to the approved zone of injection. Sand markers have no bearing on this, put an additional burden on the operator to include, and make the diagrams unreadable in many cases. Many diagrams in our field would include over 30 sand markers. When included these make the diagrams generated by our software and WellShadow unable to present the labels in a legible manner. Inclusion of the major formations and zones is more appropriate given the intent of the regulations to ensure fluid is confined to approved zone(s) of injection.

0014-64

1724.7.1(a)(14): Sand markers are interpretative and often proprietary.

Response to Comments 0003-2 and 0014-64: ACCEPTED. The requirement for sand markers has been removed from what is now proposed section 1724.7.1, subdivision (a)(15).

0003-3

1724.7.1(b)(1) and (b)(2): These sections should be deleted. Including this information on a graphical casing diagram is impractical due to physical space constraints. This type of information should be reserved for other documents such as well histories and well summaries. Inclusion of the data on the casing diagrams will cause each diagram to be a multipage document that is unmanageable and unreadable. Further, operators are unable to obtain all the cement information for wells that were abandoned by other operators and approved by the Division decades ago. If this requirement for detailed cement information remains, a Division approved abandonment should waive the requirement to submit the detailed cement information if it is not able to be obtained.

0014-62

1724.7.1(a)(9): Operators are not currently required to include tubing details, rods, downhole pumps and ancillary equipment as part of a wellbore diagram. DOGGR previously through wellbore diagrams were too busy with all these additional details.

Response to Comments 0003-3 and 0014-62: NOT ACCEPTED. Concerns about physical space constraints do not apply to digital flat files as the data can be stored even if it cannot be easily displayed. Casing diagrams in this format may be more than one page and will contain tables of data. If casing diagrams or other project data required by proposed section 1724.7, subdivision (a), cannot be obtained, proposed section 1724.7, subdivision (e), provides a procedure by which an operator may seek Division approval for an alternative data demonstration.

0014-65

1724.7.1(b)(1) and (2): Most UIC applications include hundreds of wellbore diagrams; cement calculations should only be required on wells without returns, not on every well. In addition, wellbore diagrams of all injection wells are a requirement for the Annual UIC Project reviews. Under these new

<p>wellbore diagram requirements, it appears that cement calculations would need to be done on potentially thousands of wells. Commenter believes that providing the Theoretical Tops of the Cement (TTOC) is adequate.</p>
<p><i>Response to Comment 0014-65: NOT ACCEPTED. Theoretical Tops of the Cement (TTOC) do not account for the settling that takes place after cement has been placed in the hole. They also do not consider bulges in the casing which may lead to more cement extending horizontally rather than filling the casing vertically. Cement calculations are needed to ensure that the actual amount of cement placed, and the vertical extent of that cement is known.</i></p>
<p>0007-10 1724.7.1(b)(2): Add the language “...cement type and additives <u>that would affect the long-term performance of the cement or its application...</u>”</p>
<p><i>Response to Comment 0007-10: NOT ACCEPTED. Where reporting is required regarding cement type and additives, the Division sees no justification to limit the reporting to long-term performance metrics. Instead, the requirement is for any and all information about any and all cement types and additives; it is for the Division to determine what type of additives may or may not be important for consideration.</i></p>
<p>0014-67 1724.7.1(b)(3): This requirement should be deleted altogether. Inclination and azimuth measurements were not previously requested in most recent list of casing diagram requirements from DOGGR and would require significant time and resources to update wellbore diagrams with this information.</p>
<p><i>Response to Comment 0014-67: NOT ACCEPTED. Measurements of the twists and turns of the wellbore are necessary to ensure the path of the well bore is known and true vertical depth can be accurately calculated. This information is needed to ensure accurate area of review analysis.</i></p>
<p>0003-4 1724.7(d): True vertical depth (TVD) is not pertinent to the underground injection project. TVD should be included for all <u>relevant</u> depths, including BFW, USDW, formations tops, top perforation, etc. As the draft is currently written, including MD and TVD for all depths under subdivision (a) would require an operator to include TVD for cement ports, junk/fish in well, cement plugs inside of casing, every perforation interval, etc. This information is unnecessary as these depths are generally only used with respect to their location within the casing (MD). Including the TVD for all relevant depths will provide a reference point for the other items where TVD is not required. Further, the current software used by the Division and several operators to general wellbore diagrams does not support this requirement.</p>
<p>0014-66 1724.7.1(d): True vertical depth was not previously requested in most recent list of casing diagram requirement from DOGGR and would require significant time and resources to update wellbore diagrams with this information. The need for this information would only really come up for directional or horizontal wells. True vertical depth information can be obtained from the directional surveys submitted along with the well histories for directionally or horizontally drilled wells. A potential alternative is to make this a requirement for casing diagrams for wells drilled after 1/1/2018 to avoid the re-work/cost component for the previously prepared wellbore diagrams.</p>

Response to Comment 0003-4 and 0014-66: NOT ACCEPTED. True vertical depth data provides useful information to Division, and has direct application in the calculation of maximum allowable surface injection pressure. The Division believes requiring true vertical depth data for all depths listed under proposed section 1724.7.1, subdivision (a), is an appropriate default. If an operator believes providing these casing diagram data presents an unreasonable burden, proposed section 1724.7, subdivision (e), provides a procedure by which an operator may seek Division approval for an alternative data demonstration.

0013-13

1724.7.1(e): The proposed regulations would eliminate the requirement to submit casing diagrams. DOGGR reasons that because the *regulator* has software that can recreate casing diagrams based on submitted data, diagrams are no longer needed. The public benefits from having casing diagrams available, and those studying casing diagrams for potential hazards may not necessarily have the software needed to create a casing diagram from the raw data.

Response to Comment 0013-13: NOT ACCEPTED. The proposed regulations do require operators to submit casing diagrams as part of the data supporting an underground injection project. See proposed section 1724.7, subdivision (a)(1)(C)(iii). The proposed regulations allow operators the option to submit casing diagrams either as a graphical documents or flat file data sets. Potentially confusing language in proposed section 1724.7.1, subdivision (e), regarding operating submitting flat file data sets "in lieu of graphical casing diagrams" has been revised to clarify that the graphical casing diagrams and flat file data sets are two methods of providing the same information. Compared to fixed graphical diagrams, flat file data sets are often a more convenient vehicle for containing and flexibly accessing a large amount of information. The Division anticipates that it will have features on its public website enabling interested members of the public to view graphical representations of flat file casing diagrams.

0014-68

1724.7.1(e):

Commenter proposed making the following additions (underlined) and deletions (strikethrough) to the text of a pre-rulemaking discussion draft version of what is now proposed section 1724.7.1, subdivision (e):

Unless DOGGR elects to construct casing diagrams using the WellStar database, casing diagrams shall be submitted as both a graphical diagram and/or as a flat file data set using a template provided by the Division in noncustom software.

Commenter suggests that the additions provide necessary clarity regarding the format of flat file data submissions, and confirmation that the Division will not require operators to purchase custom software in order to make use of this regulatory option.

Response to Comment 0014-68: NOT ACCEPTED. A flat file is a simply a file that contains data that is not structurally related. It can contain delimiters such as commas or tabs, but usually contains no indices or direct record access method. Flat files can be documents, spreadsheets or textual records, and can be produced by many common programs including Microsoft Excel. Comment extensions for a flat file are .txt and .csv. The Division does not agree that the additions suggested by this comment add helpful clarity.

1724.7.2 Liquid Analysis

0008-8

1724.7.2: Commenter recommends that fluid to be injected into Class II disposal wells be tested to determine if the waste is a hazardous waste by sampling and testing the waste according to the methods set forth in California Code of Regulations, title 22, division 4.5, chapter 11, article 3 (section 66261.20 et seq.) or according to an equivalent method approved by the Department of Toxic Substances Control pursuant to California Code of Regulations, title 22, section 66260.21, except where the operator has determined that the waste is excluded from regulation under California Code of Regulations, title 22, section 66261.4 or Health and Safety Code section 25143.2. Any wastes that are determined by such testing to be hazardous wastes must be managed in compliance with all hazardous waste management requirements of the Department of Toxic Substances Control.

Response to Comment 0008-8: NOT ACCEPTED. As part of the injection plan component of the project data requirements, proposed section 1724.7, subdivision (a)(3)(H), requires the operator of an underground injection project to identify the sources of the injection liquid and to provide the Division with an analysis of the injection liquid. Similarly, proposed section 1724.10, subdivision (d), requires the operator to provide the Division with an updated representative chemical analysis of the injection liquid whenever the source of the injection liquid is changed, or upon request from the Division. Proposed section 1724.7.2 prescribes various protocols for collecting, conducting, and reporting the results of the liquid analysis. Implementation of the California Hazardous Waste Control Law and related provisions referenced by the commenter is outside the scope of this rulemaking action.

0019-4

1724.7.2: The regulations need more robust testing of injection fluids to ensure accurate data and increase transparency. We offer greater specificity in the in-line edits, including a recommendation for quarterly testing of injection fluids that aligns with SB 1281 water use and disposal reporting requirements. The SB 4 and SB 1281 reporting website and data management systems currently in operation by the Division are well equipped to handle chemical data submitted in relation to injection projects and increased testing frequency, making increased chemical reporting and monitoring relatively simple to implement and share publicly.

Response to Comment 0019-4: NOT ACCEPTED. The SB 4 and SB 1281 reporting protocols are specific to the legislative instructions that were received regarding those programs. The Division does not agree that a fixed schedule of quarter-annual injection fluid testing for all wells is necessary. Proposed section 1724.10, subdivision (d), requires the operator to provide the Division with an updated representative chemical analysis of the injection liquid whenever the source of the injection liquid is changed, or upon request from the Division. The Division anticipates that liquid analysis data will be publicly available via the SWRCB GeoTracker system.

0014-69

1724.7.2(a): Although this provision is consistent with the Notice to Operators – Water Sampling Protocols and Analyses of Injection and Formation Waters issued by DOGGR in May 2015, Commenter recommends that fluid analysis should be limited to a standard geochemical analysis where the injection zone contains greater than 10,000 TDS. As drafted, the requirement is inconsistent with

DOGGR's stated goal of requiring water testing appropriate for the risks and needs. Commenter is proposing to differentiate fluid testing based on TDS levels of injection zones.

Response to Comment 0014-69: NOT ACCEPTED. *This comment refers back to a pre-rulemaking discussion draft version of proposed section 1724.7.2. The regulatory text in the version referenced by the comment differs substantially from the version proposed in this rulemaking action. As discussed more fully in the Initial Statement of Reasons, in developing the proposed regulations the Division consulted with the State Water Resources Control Board to identify a baseline list of analytes suitable for evaluating the influence of underground injection projects on nearby subsurface water. Reducing or forgoing the proposed liquid analysis requirement for injection into areas of higher TDS groundwater would not provide an equivalent regulatory benefit to the testing requirement as proposed. Water with a concentration of TDS of 10,000 mg/L or greater may still be subject to beneficial use and may be a valuable natural resource. Liquid analysis also aids in evaluating the ongoing efficacy of confinement of injected fluid to the approved injection zone—a key criteria that does not vary based on TDS. Liquid analysis provides a useful regulatory tool even where injection occurs into an area with high TDS groundwater.*

0008-7

1724.7.2(a): Commenter objects to the Division's proposal to significantly narrow the list of analytes that must be tested for routinely. Commenter requests that the Division restore the original list of analytes and that benzene, toluene, ethyl benzene, and xylenes be added to the list of analytes.

0013-14

The proposed list of chemicals to be tested is far too limited to adequately account for the range of chemicals commonly associated with oil and gas operations. Section 1724.7.2 does not include testing for common volatile organic compounds such as BTEX chemicals (benzene, toluene, ethylbenzene, and xylenes). DOGGR states that its list of analytes was restricted primarily due to costs rather than risk, frequency of use, or potential damage

Response to Comments 0008-7 and 0013-14: NOT ACCEPTED. *Proposed section 1724.7.2, subdivision (a), requires that liquid analysis include testing for total petroleum hydrocarbons as crude oil. This total petroleum hydrocarbon panel includes testing for volatile organic compounds such as BTEX. The Division believes the list of analytes required by proposed section 1724.7.2, subdivision (a) provide a sufficient informational baseline for fluid analysis. The Division has existing authority to require additional testing on a case-by-case basis, if circumstances warrant.*

0006-3

1724.7.2(c): The project data requirements call for an analysis of the (proposed?) injection liquid, but the liquid analysis section itself calls for an analysis of the injection liquid after additives are added and/or treatment is conducted. Neither of those steps will have occurred at the time of permit application, so strict compliance with the proposed rule in 1724.7(a)(3)(H) as current written would not be possible.

Response to Comment 0006-3: NOT ACCEPTED. *As articulated in proposed section 1724.7.2, subdivisions (d), the proposed regulations contemplate an ongoing requirement for operators to ensure that the liquid analysis on file with the Division is representative of the liquid actually injected. The Division anticipates that operators will need to update the liquid analysis from time to time.*

0006-4

1724.7.2(c): The rule does not define or provide thresholds for “significant change” as articulated in 1724.10(d). As the Division knows, the nature of injectate can change from hour to hour in an arguably significant fashion. Providing some guidance around this, along with the meaning of “constituent source” would help ensure that the Division gets the information it needs for regulatory decision-making in a timely fashion without creating undue burden for industry.

Response to Comment 0006-4: ACCEPTED IN PART. If the injection liquid changes such that the original sample analysis provided is no longer representative of the liquid currently being used, a new sample analysis must be provided to the Division. This data must be updated every time the sample is no longer representative. Proposed section 1724.10, subdivision (d), has been modified to clarify this point. As modified, the phrase “significant change to the relative contribution of individual sources” is now further explained by the following qualification: “such that the last chemical analysis is not representative of the liquid being injected.”

As used in proposed section 1724.10, subdivision (d), “constituent source” was intended to mean a contributing source. For the sake of the clarity, “constituent” has been replaced with “contributing” in proposed section 1724.10, subdivision (d).

0002-14, 0007-12

1724.7.2(d): Commenter strongly believes operators should be allowed to verify the accuracy of data before submittal to the Division and recommends text edits to require the operator not the performing laboratory to submit liquid analysis data to the Division.

Response to Comments 0002-14 and 0007-12: NOT ACCEPTED. If an operator believes that test results provided by a lab to the Division contain errors, the operator may contact the Division and explain why a correction is necessary. The Division believes such errors are likely to be infrequent and can be addressed on a case-by-case basis.

0014-70

A pre-rulemaking discussion draft version of proposed section 1724.7.2, subdivision (d) incorrectly referenced the Department of Public Health as the source of the environmental laboratory accreditation program. The commenter suggested changing “Department of Public Health” to “State Water Resources Control Board,” the correct entity.

Response to Comment 0014-70: ACCEPTED. The Division made the correction as suggested prior to commencing this rulemaking action. The correction is reflected in the text of the regulations as initially proposed.

0019-19

Commenter recommends making the following additions (underlined) to the proposed regulations:

- 1724.7(a)(3)(H): Add: “Identification of the source(s) of the injection liquid(s) and an analysis of...”
- 1724.7.2(e): Add: “(e) Complete list of chemical additives, following the format and requirements established under SB 4 for well stimulation fluids.”
- 1724.7.2(f): Add: “(f) The source(s) of all injected fluids, including but not limited to freshwater sources(s), and/or production wells(s), of any produced water is injected.”

Response to Comment 0019-19: ACCEPTED IN PART. “Source” has been changed to “source(s)” at proposed section 1724.7, subdivision (a)(3)(H), as suggested.

Proposed section 1724.10, subdivision (e), requires the operator of an injection well located within 500 linear feet of the screen or perforations of a water supply well to provide the Division with all of the following information, updated on an annual basis: the safety data sheet for each chemical added to the injected fluid, the aggregate weight of each additive, a description of the purpose of each additive, and a water treatment process flow diagram depicting all physical and chemical treatment processes applied to the injected fluid, from its source to the injection well. Additionally, proposed section 1724.10, subdivision (e), has been amended to clarify that, on a project-specific or well-specific basis, the Division may specify a distance greater than 500 feet as the distance that triggers the additive-reporting requirements of this subdivision if, in the Division’s judgment, geological conditions or the relative location of any water supply well warrants the additional data collection. The Division believes these provisions will be adequate to obtain chemical additive information where necessary to facilitate the Division’s regulatory mission of preventing damage to life, health, property, and natural resources.

Adding a separate regulatory requirement to report the source of all injected fluids is not necessary. Proposed sections 1724.7, subdivision (a)(3)(H) and 1724.10, subdivision (d), already require operators to provide a laboratory-accredited analysis of the injection liquid, updated as needed to ensure that the analysis is representative of the actual liquid injected. Other existing law already requires operators to file monthly reports regarding the disposition of water in oilfield operations, including the source and volume of fluids produced from and injected into each well. See PRC section 3227, subdivision (a)(5).

1724.8 Evaluation of Wells Within the Area of Review

0008-12

1724.8: The Division should explicitly state that all corrective action deemed necessary as a result of the evaluation required in this section must be complete before injection will be allowed to commence.

Response to Comment 0008-12: ACCEPTED IN PART. The Division will not approve injection that has the potential to result in fluid migration outside of the approved zone, and operators carry the burden of taking whatever steps may be necessary to provide assurances of fluid confinement. Section 1724.8(a)(1) and (2) have been revised to be clear that the additional work to address potential conduits may be required as an approval condition for an injection project. For existing projects, the Division has the authority to halt injection in response to any concerns that fluid may be migrating outside the approved injection zone.

0019-24

1724.8(a): Add: “...or the creation of new pathways...”

Response to Comment 0019-24: NOT ACCEPTED. This language would be redundant as it would be impossible to create new pathways without fluid migration. The Division is focused on fluid migration and the potential for creation of new pathways would already be included in that inquiry.

0018-12

1724.8(a): Because water has such a low compressibility, any injection causes migration out of the injection volume. Even if this volume is a compartment with low permeability seals on all sides, migration will occur through those seals to regions outside the injection zone. Consequently, a zero-migration criterion would mean disposal projects could not occur in practice nor could any enhanced recovery project that raises pressure over original. This is too stringent a definition of the AOR.

Response to Comment 0018-12: NOT ACCEPTED. In order to ensure that injection will not cause damage, the scope of the approved injection zone must reflect the outer limits of where fluid migration may occur without threatening such damage, and the scope of the area of review must reflect the area of influence of the contemplated injection operations. The area or influence of contemplated injection operations should not go beyond the outer limits of where fluid migration may occur without threatening such damage.

0006-5

1724.8(a)(new): This section should provide heightened scrutiny for idle wells as it does for plugged and abandoned wells, with explicit language for accelerating their plugging schedule as appropriate. “(x) All idle wells within the area of review, and all existing producing or injection wells within the area of review that have not been used for injection or production for more than 180 days, shall demonstrate external and internal mechanical integrity per (a)(1), and within two years either be repaired and returned to service or permanently plugged and abandoned with cement plugs emplaced across all hydrocarbon zones, flow zones, corrosive zones, lost circulation zones, the base of the USDW interface, and the base of the freshwater interface.”

Response to Comment 0006-5: NOT ACCEPTED. Idle wells are governed by statute and regulations in development concurrently with this rulemaking. With that in mind, this section requires that all wells within the area of review be evaluated for the potential to allow fluid to migrate outside the approved zone; this would include idle wells.

0008-9

1724.8(a)(1): Commenter recommends that the identification and assessment of wells (or other features) that could allow injected fluids to migrate outside the approved injection zone or otherwise endanger life, health, property, or natural resources should be required not just for wells that penetrate the injection zone but for all penetrations of the confining zone(s), including but not limited to wells or mines.

Response to Comment 0008-9: ACCEPTED. The commenter’s concern is addressed by the regulations. Section 1724.8 focuses heavily on wells penetrating the AOR because those wells are the most likely conduits for fluid migration out of the approved injection zone. But the performance standard of section 1724.8(a) calls for evaluation of any potential fluid migration outside of the approved injection zone, and section 1724.7(a)(1)(B) requires identification of wells adjacent to the boundary of the AOR and identification of mining and other subsurface industrial activities within the AOR.

0018-13

1724.8(a)(1): This implies that a directional well intersects a deeper zone but not the injection zone need to be shown and evaluated. That does not seem necessary as such a well would not be a potential conduit other than secondarily if leakage occurs via another path into a zone that is intersected by the directional well.

<p>Response to Comment 0018-13: NOT ACCEPTED. <i>Wherever a well may be a conduit, even if just a secondary conduit, it must still be evaluated to ensure it will not lead to fluid migration outside the approved zone.</i></p>
<p>0018-59 1724.8(a)(1): Minor text edit, “...penetrating the <u>proposed</u> injection zone for the underground injection project or a deeper zone...”</p>
<p>Response to Comment 0018-59: NOT ACCEPTED. <i>This requirement also applies to existing projects, so “proposed” is not appropriate. The Division sees no reason to remove “for the underground injection project” as that is the appropriate reference for the injection zone.</i></p>
<p>0004-9 1724.8(a)(2): The proposed UIC regulations contain an abbreviated abandonment requirement and is not in sync with abandonment requirements of CCR 1723.1 especially 1723.1(c) which addresses special requirements for particular types of hydrocarbon zones, and (d) which allows bridge plugs under certain conditions.</p>
<p>Response to Comment 0004-9: ACCEPTED. <i>The specifications in proposed section 1724.8(a)(2) have been replaced with to the existing requirements of section 1723.1.</i></p>
<p>0007-13 1724.8(a)(2): Add language allowing for “<u>approved materials such as Bentonite</u>” in lieu of cement for plugged and abandoned wells. The use of Bentonite and similar technology may be a better material. Including options to cement allows technology to develop methods that may one day replace cement. It also allows the use of other materials that in the situation may be a better engineering or business choice.</p>
<p>0018-14 1724.8(a)(2): I have heard of the use of other materials that perform better than cement for difficult situations. Like a tin-bismuth alloy that is radiofrequency melted in a vessel downhole and then released onto a bridge plug to both flow out through squeeze perforations to remediate a leaking annular seal and plug the inside of the casing at the same time.</p>
<p>0014-73 1724.8(a)(2): The requirement for 100 feet of cement does not necessarily address isolation. For example, in some cases high weight mud can provide adequate isolation as long as pressure does not allow it to be pushed into a USDW.</p>
<p>Response to Comments 0007-13, 0018-14, and 0014-73: ACCEPTED IN PART. <i>The Division is aware that there may be alternatives to cement which would serve the same purpose for zonal isolation. Rather than attempt to delineate all the alternatives, section 1724.8(a)(3) allows for an alternative demonstration that a plugged and abandoned well within the AOR will not be a potential conduit for fluid migration outside the approved zone. Where a well has been plugged using materials other than cement, the operator must demonstrate to the Division that this performance standard has been met.</i></p>
<p>0008-10 1724.8(a)(2): We remain concerned that simply requiring plugged and abandoned wells to have cement as indicated is not sufficient to ensure that plugging is adequate and that such wells will not serve as potential migration pathways for injected fluids to reach protected water sources. We recommend that the Division update its well plugging requirements and require that all plugged and</p>

<p>abandoned wells in the AoR meet these standards. At a minimum, the Division should require that all plugged wells in the AoR meet the Division’s existing plugging standards at Cal. Code Regs., tit. 14, §§ 1723–1723.8, although we reiterate that these regulations are outdated and do not conform to current best practices for well plugging. The Division should also explicitly state that wells that do not meet these standards must be replugged.</p>
<p>0018-15 1724.8(a)(2): Should the linking word between “injection zone” and “the oil and gas zone” be “and” instead of “or”? If not, to which of these markers does the 100-foot above requirement apply? The shallowest?</p>
<p><i>Response to Comment 0008-10 and 0018-15: ACCEPTED IN PART. The specifications in proposed section 1724.8(a)(2) have been replaced with the existing requirements of section 1723.1.</i></p>
<p>0014-10 1724.8(a)(2): Commenter is concerned about the provision in this section allowing the Division to require re-entry of previously plugged and abandoned wells to “manage identified containment assurance issues.” In many cases, such intervention poses serious operational and safety risk and can jeopardize the USDW isolation. The regulations should be revised to clarify that requests to re-enter a previously abandoned well based on “identified containment assurance issues” should be based on actual evidence of communication between the injection zone and USDW and must recognize the operational risk and feasibility of the desired remediation.</p>
<p>0002-16, 0017-3 1724.8(a)(2) and (a)(3): The implementation of the finalized UIC regulations should not require undue reopening of previously plugged and abandoned wells introducing unnecessary complexity, costs, and risks. Requests to reenter a previously abandoned well by the Division should be based on evidence of communication between the zone and fresh water and should consider the operational risk and feasibility of the desired remediation. Operations have made significant investment in the ongoing development of existing UICs based on past Division approval of operations. These regulations should clarify that the ultimate goal is to have a barrier preventing communication between the injection zone and USDW. Reentry (a)(2) should be limited to “<u>accessible</u>” wells “<u>provided such effort does not pose undue risk to USDW isolation</u>”. The Division may “<u>review</u>” alternative “<u>evidence indicating</u>” that the well will not be a conduit for fluid migration “<u>between the injection zone and a USDW.</u>”</p>
<p>0014-9, 0014-73 1724.8(a)(2) and (a)(3): These sections should be revised to state that wells within the area of review that were previously plugged and abandoned with the approval of the Division should be exempt from the cementing requirements if they do not pose a risk to a USDW or other protected water. Operators have made significant investments in the ongoing development of existing UIC projects, including plugging and abandoning idle wells, based on past Division approvals. The regulations should not be written in such a way that these past approvals are of no consequence, contrary to the rights of oil and gas mineral owners and operators. Commenter is concerned about the requirement to re-enter previously plugged and abandoned wells, as in many cases such intervention poses serious operational and safety risk and can jeopardize the USDW isolation.</p>
<p><i>Response to Comments 0014-10, 0002-16, 0017-3, 0014-9 and 0014-73: NOT ACCEPTED. The Division has the statutory duty to protect life, health, property, and natural resources, and concerns that a well</i></p>

within the AOR of an injection project may be a conduit for the migration of fluid outside the approved injection zone must be addressed. Such concerns might be addressed by conducting testing or monitoring to demonstrate that migration is not occurring, by modifying the parameters of the injection operations to avoid the potential conduit, or by remediating the potential-conduit well to address the concern. But if there are concerns that an injection project is causing migration of fluid outside the approved injection zone, then those concerns cannot be ignored, even if the concerns were not identified in the course of prior review and approval by the Division.

When determining the extent of the approved injection zone and conducting review of the AOR, the Division's primary focus is protection of USDW. But the location of USDWs is not the only factor in determining the extent of the approved injection zone. The approved injection zone may reflect a conservative buffer around a USDW zone, there may be a need to protect groundwater that does not meet the definition of a USDW, and hydrocarbon reservoirs must be protected from infiltrating water or other detrimental substances.

0008-11

1724.8(a)(3): Given commenter's concerns regarding the Division's plugging requirements, it is not appropriate at this time to allow operators to make an alternative showing that the well will not be a conduit for fluid migration for wells that don't meet plugging requirements.

Response to Comment 0008-11: NOT ACCEPTED. *The status of existing plugging requirements in regulations should not affect the ability of the Division to evaluate alternatives to those requirements where an operator can demonstrate that the current plugged configuration of the well will prevent damage to life, health, property, and natural resources by ensuring that all fluids are confined to the appropriate zone.*

0018-16

1724.8(a)(3): Change as follows: "...do not meet the ~~element~~ plugging specifications..."

Response to Comment 0018-16: ACCEPTED. *The text has been changed as recommended.*

1724.10 Filing, Notification, Operating, and Testing Requirements for UIC Projects

0019-25

1724.10(a): Add: "...change in injected fluid, change in purpose of the project (such as from enhanced recovery to disposal...and obtaining a new or modified project approval letter."

Response to Comment 0019-25: NOT ACCEPTED. *This section prompts operators to proactively identify upcoming operational changes that will call for the Division's review and approval. This section lists examples of the types of changes that would be inconsistent with the current conditions of approval, and would necessitate Division staff time to consider a change in the PAL. The suggested additions are not necessary and would not further the purpose of this section.*

0014-75

1724.10(a): Commenter recommends replacing "increase in size" with "expansion of the project, and "injection pressure" to "maximum allowable surface pressure".

Response to Comment 0014-75: ACCEPTED. *The language has been edited as recommended by Commenter.*

0003-5
1724.10(b): Where prior written approval is required for resumption of injection, clarification is needed. Does this statement automatically rescind the injection permit once the well becomes idle requiring the operator to apply for a new permit once the well is activated?
<i>Response to Comment 0003-5: NOT ACCEPTED. The specific text referenced by the commenter has been deleted and replaced with a substantively identical but more clearly articulated requirement at section 1724.13. Section 1724.13(a)(8) requires cessation of injection and notification to the Division when an injection well becomes idle, unless the operator has specifically requested, and the Division has granted, allowance for the well to remain approved for injection while idle. Section 1724.13(b) further provides that once an injection well has been required to cease injection under section 1724.13(a), the operator may not resume injection in that well without subsequent written approval from the Division. Documentation of the Division's approval of the modification of an underground injection project or resumption of suspended injection operations would not effect a total rescission of the Project Approval Letter. Section 1724.6(d) explains that Project Approval Letters are subject to suspension, modification, or rescission, and Section 1724.6(c) requires documentation of modifications to an underground injection project, either by addendum or revision of the Project Approval Letter.</i>
0007-14
1724.10(b): Commenter would remove the language related to resumption of injection in an injection well that has become an idle well. Without that language, the process described in this section is consistent with current DOGGR practices and ensures DOGGR is notified of injection starting in an idle well, and the required tests are performed in a timely manner.
<i>Response to Comment 0007-14: ACCEPTED IN PART. This language has been moved, to Section 1724.13(a)(8), which provides that injection approval is suspended for a well that becomes an idle well as defined by Public Resources Code section 3008, subdivision (d). Where needed, an operator may retain the approval to inject in an idle well upon request granted by the Division</i>
0014-76
1724.10(b): Are dual notices required, for drilling and commencement of injection operations?
<i>Response to Comment 0014-76: ANSWER. Yes, dual notices are required as approval for an underground injection project is separate and distinct from the approval to drill a well.</i>
0014-77
1724.10(b): Clarification is needed whether notification to and approval of the Division applies only when changing a well to injection, or whether it also applies to conversion of a cyclic well to a rod pump producer?
<i>Response to Comment 0014-77: ANSWER. A cyclic steam well is specifically permitted as a dual purpose well; injection and production. Thus, a shift from its injection phase to its production phase should not be considered a conversion requiring notification and approval. Where a cyclic steam well is being reworked to a new configuration that was not contemplated at the time of original permitting, notification and approval are required.</i>
0019-26
1724.10(b): Add: “...and obtaining a new or modified project approval letter.”
<i>Response to Comment 0019-26: NOT ACCEPTED. This section already refers to written approval of the Division in accordance with Section 1724.6, which is the Project Approval Letter section.</i>

0019-27

1724.10(c): Add: “...The Division shall post all injection data online within 10 days of receipt. The injection report shall include the following information: dates of injection, purpose of injection, volume of injected fluids, source of injected fluids, daily maximum injection pressure, all chemical additives injected, their purpose, mass, concentration, CASRN following the format established under SB 4 for well stimulation fluids.”

Response to Comment 0019-27: NOT ACCEPTED. PRC section 3227 already requires operators to report the source and volume of injected fluids, the regulations require continuous pressure monitoring and recording, the project data requirements include a statement of the primary purpose of the injection project, and chemical information for additives used in a well that is proximal to water source wells is required to be disclosed. The Division does make that information available to the public.

0014-78

1724.10(d): Since injection is occurring in exempt aquifers, the chemical analysis should only be required at the outset of the project, unless it is significantly or substantially modified. Requiring new analyses every two years adds to project costs and loses sight of all the effort that was put into validating the exempt status to begin with.

Response to Comment 0014-78: ACCEPTED IN PART. This section was modified to require a new analysis any time the fluid is changed such that the submission on file is no longer representative of the fluid actually being injected. The Division may request additional analysis on a case-by-case basis.

0008-13

1724.10(d): Commenter objects to the proposed revision removing the requirement to test the liquid being injected at least once every two years.

Response to Comment 0008-13: NOT ACCEPTED. The fluid analysis must be done frequently enough to ensure that it is representative of the liquid being injected. For some projects, such as commercial disposal wells, this will be substantially more frequent than every two years, for other more static projects it could be more than two years. The Division may request additional fluid analysis as needed on a case-by-case basis. In addition, the quarterly report required under Public Resources Code section 3227 includes source and volume of any water reported, along with water used to generate or make up the composition of any injected fluid or gas. It also includes water used to generate or make up the composition of any injected fluid or gas. Thus, much of this information is already available on a quarterly basis for public review under the statutory reporting requirements.

0016-1

1724.10(d): Commenter seeks clarification to what extent a change to the relative contribution of constituent sources refers to. For example, does this requirement extend to the produced water from one well and reinjected into another well for waste water disposal? Commenter suggests the requirement does not apply to produced water which does not have added constituents.

Response to Comment 0016-1: NOT ACCEPTED. This section applies to the liquid being injected, no matter its source, and would include produced water from one well reinjected into another well for waste water disposal. Language in this section has been modified to require analysis when a “contributing” source rather than a “constituent” source is changed.

0019-28	<p>1724.10(d): More specificity is needed to define changes in fluid source. Any change must trigger a new analysis, and a time-based frequency is needed to ensure that changes that occur over time in the fluid chemistry from a single source are recorded and reported. Add: “...or on a quarterly basis (whichever is shorter in duration)...such as a production well which provides produced water...”</p>
<p><i>Response to Comment 0019-28: NOT ACCEPTED. The regulation requires that the fluid be reported anytime there is sufficient change so that the fluid sample on file no longer is representative of the fluid being used. This could mean monthly testing or annual testing, or something more or less frequent depending on operations. Where a fluid does not change regularly, the Division may request additional analysis on a case-by-case basis, but quarterly reporting in all cases may not be necessary. Where it changes more frequently, it would not be enough.</i></p>	
0018-17	<p>1724.10(d): The regulation does not appear to contain a definition of significant. This makes this portion of the regulation subject to interpretation by both parties involved, operators and the Division. A significant change could be defined as injection from a new zone, initiation of a new production approach (such as a shift from primary to secondary production, or one type of EOR to another), and application of a new treatment technology to the injectate upstream of the well.</p>
<p><i>Response to Comment 0018-17: ACCEPTED IN PART. Language has been added to the text to clarify that the significant change is one that would result in the last chemical analysis no longer being representative of the liquid being injected.</i></p>	
0018-18	<p>1724.10(d): Commenter suggests the regulations require periodic reanalysis of the injectate to characterize changes that are occurring in the source zone as a result of production activities, such as the application of EOR.</p>
<p><i>Response to Comment 0018-18: NOT ACCEPTED. Review of the injectate will take place periodically as part of the periodic project review, but it is not necessary to describe such review in regulation.</i></p>	
0006-6	<p>1724.10(e): When injection occurs in close proximity to water supply intakes, enhanced scrutiny of the injection fluid is reasonable to determine risk to public health from potential drinking water contamination. Without commenting on the selection of five hundred feet at the default trigger for analysis and publication of injectate chemistry, commenter suggests inserting an explicit mechanism for the Division to enlarge that distance if geological conditions or other evidence indicate that the injectate might travel further to a water intake. “...<u>or other such distance as specified by the Division on a case-by-case basis...</u>”</p>
<p><i>Response to Comment 0006-6: ACCEPTED. This provision has been modified to specify that the requirement may apply at a greater distance in cases where the Division determines that it is warranted based on geological conditions or the relative location of any water supply well.</i></p>	
0008-14	<p>1724.10(e): Commenter recommends that this information be provided for all underground injection projects, not only those that include an injection well with open perforations located within five hundred feet of the screen or perforations of a water supply well. Chemical disclosure is not only</p>

important to help respond to contamination of water wells, as noted in the Initial Statement of Reasons, but also to protecting worker and public health and safety and reducing toxic air emissions.

Response to Comment 0008-14: NOT ACCEPTED. The Division does not generally have a need for chemical disclosure, as zonal isolation must be maintained regardless of the content of the fluid injected. The purpose of this requirement is to collect information that could be used to verify whether injection fluid is contaminating water supply wells. Obtaining information about chemical additives in injection fluid would help the Division and other regulators respond if contamination is reported in water supply wells located near injection wells.

0019-3

1724.10(e): The proposed regulations must be strengthened to provide greater transparency to the public regarding the use of chemical additives in injection wells. While the proposal envisions enhanced reporting of chemical additives in some limited scenarios where injection wells are in close proximity to water wells, the two-tiered disclosure arrangement is inadequate. According to the Standardized Regulatory Impact Statement (SRIA) for this proposal provided by the Division, the enhanced reporting requirements for this subset of wells only adds a cost of \$1,000 per injection project and can be satisfied with document retention, basic aggregation and submittal. As noted in the SRIA, the enhanced reporting would only apply to approximately 10% of injection projects. The SRIA explains why this level of increased reporting is important, however there is no good reason given for why it should only be applied to such a small subset of projects and wells. This section of the regulations is one of the least costly to operators of any regulatory requirement and expanding it to all injection projects would simplify and standardize data submittal and transparency. When the Legislature adopted SB 4, it required complete disclosure of all chemical additives used in well stimulation in a manner that prioritized the public's right to know about potentially hazardous materials discharged into the environment. In the interest of fulfilling that mandate, the Division should apply the same standard of transparency to injection projects.

Response to Comment 0019-3: NOT ACCEPTED. The Division does not generally have a need for chemical disclosure, as zonal isolation must be maintained regardless of the content of the fluid injected. The purpose of this requirement is to collect information that could be used to verify whether injection fluid is contaminating water supply wells. Obtaining information about chemical additives in injection fluid would help the Division and other regulators respond if contamination is reported in water supply wells located near injection wells.

0019-29

1724.10(e): For a number of reasons, the disclosure of chemical additives must be required for all wells and all injection projects. The bifurcated requirements proposed in the regulations is not adequate. First, the 500-foot buffer appears arbitrary. If the Division insists on limiting this vital information to only a subset of injection projects, it should justify why this distance is appropriate. Any such distance should be between the outermost boundary of the injection zone and the first encountered groundwater with potential beneficial uses. Setting the boundary from perforation of injection zone to screen of the water well is not protective of water resources and does not account for future water wells that have not been drilled. Additionally, any injection well that passes through groundwater with beneficial uses must also be subject to the enhanced reporting requirements (if a two-tiered scheme exists. Which it shouldn't.) Commenter recommends that these requirements be

applied to all underground injection projects and deletes text limiting the requirement to wells located within 500 feet of a water well.

Response to Comment 0019-29: ACCEPTED IN PART. *The Division acknowledges that a default 500-foot distance may not be appropriate in all circumstances. As such, the regulation was modified to allow the Division to request the chemical additive information on “a project-specific or well-specific basis” at “a distance greater than 500 feet as the distance that triggers the requirements of this subdivision if, in the Division’s judgment, geological conditions or the relative location of any water supply well warrants the additional data collection...” Nonetheless, the Division does not see a regulatory need for additive information on all injection wells. Where a water well is near an injector, this information is necessary for investigative purposes, and can be requested from other wells as needed.*

0018-19

1724.10(e): Commenter appreciates the need to have a criterion, however is not aware of a scientific basis for this formulation. In order to protect USDW, the criterion should regard distance between the injection zone and USDW. The criterion could be based on the presence of a sufficiently transmissive interval between the injection zone and the base of USDW. Numerical simulations show that such intervals, termed “dissipation intervals” in the Air Resources Board’s pending geologic carbon storage permanence protocol, substantially reduce the risk of leakage to USDWs via wells.

Response to Comment 0018-19: ACCEPTED IN PART. *The Division acknowledges that a default 500-foot distance may not be appropriate in all circumstances. As such, the regulation was modified to allow the Division to request the chemical additive information on “a project-specific or well-specific basis” at “a distance greater than 500 feet as the distance that triggers the requirements of this subdivision if, in the Division’s judgment, geological conditions or the relative location of any water supply well warrants the additional data collection...”*

0002-18, 0014-1, 0014-4

1724.10(f): The majority of injection wells across the state do not have the equipment to facilitate continuous recording of injection pressure in place today and there is limited value in obtaining that data at greater frequencies than current operations require. Injection system pressures do not fluctuate in a manner that require the constant monitoring of each well. Obtained at a significant cost, this information will have no substantial impact on the Division’s goals with the UIC program. Air gapping should be an acceptable alternative to monitoring inactive wells. With the requirements to submit the highest instantaneous injection pressure for the month there is room to introduce a great deal of confusion i.e.: assuming that the highest pressure is associated with the average daily injection volume may make a well appear to be operating outside the approved limits when in fact that was not the case. Commenter proposes submitting the average operating pressure which will align with the average injection volumes reported monthly and provide a clearer picture of the well’s operations.

0002-2

1724.10.1: The proposed regulation continues to impose unnecessary testing on operators. In the case of cyclic steam operations, it is unnecessary to impose continuous monitoring. These operations do not create significant stress on a wellbore and do not occur as frequently as other operations.

0014-80	1724.10(f): Commenter recommends changes to bring this section in line with 40 CFR 146.23(b)(5) which indicates that manifold monitoring may be used.
0017-5	1724.10(f): The Division's draft changes the longstanding requirement for regular monitoring of well-specific injection pressure to an unwarranted requirement for continuous monitoring. Regarding the continuous monitoring of well-specific injection pressure, any monitoring requirements should be limited to active wells. We propose that DOGGR expressly include air-gapping as an alternative option to continuous monitoring, which precludes injection into the well without approval and makes further monitoring unnecessary. There is no timeline given for implementation but more importantly there is limited value in obtaining that data at greater frequencies than current regulations require. Injection system pressures do not fluctuate in a manner that require the constant monitoring of each well. Obtained at a significant cost, this information will have no substantial impact on the Division's goals with the UIC program. We propose that DOGGR return to its previous draft which stipulated that wells must be outfitted with well-specific gauges to allow for regular monitoring of the wells injection pressure.
0014-79	1724.10(f): Dedicated well-specific pressure gauges on every steam injector will pose major capital expenses. Orifice plate on cyclic wells can be used as an alternative for a more reasonable cost-effective solution on that category of wells. Commenter recommends that operators have the flexibility to use alternatives to well-specific pressure gauges, subject to DOGGR approval. Systems that do not have well specific automated pressure management commonly have spilitigator measurement. Commenter believes that measurement suffices.
0004-10	1724.10(f): It should be acceptable to monitor the pressure of the well at the steam header where we can provide a well specific pressure measurement. This is not clear from the wording. A Barton chart recorder requirement is acceptable (which will not provide an automatic computer alarm). The text is not clear although we understand it is meant to be an accepted compliance method. It is unclear whether pressure needs to be measured when a cyclic well is producing oil. This should be excluded from this requirement.
0012-1	1724.10(f): While we acknowledge the intent of the wording, we believe that the regulatory emphasis should be on identifying and isolating potential problem anomalies in as rapid a fashion as possible. Towards that end, we encourage DOGGR to modify the wording to allow compliance to be achieved through use of a monitoring system that can isolate individual well behavior. Recommended language: <u><i>“Alternatively a system injection pressure with the ability to isolate data associated with an individual well on a system or another Division approved method shall be acceptable.”</i></u>
0014-2	1724.10(f): It should also be noted that the Code of Federal Regulations recognizes it is not necessary to monitor at the wellhead; instead, centralized manifold monitoring on a field or project basis is an appropriate alternative. Specifically, 40 CFR § 146.23(b)(5), provides that:

“Hydrocarbon storage and enhanced recovery may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring.” Commenter is confident that centralized monitoring systems can provide the necessary technical assurance that approved well pressures will not be exceeded. Nevertheless, if DOGGR remains intent on requiring well-specific continuous monitoring/recording, it should be limited to the installation of new UIC wells, not to existing projects. The regulations should also clearly outline examples or classifications of alternatives that the Division considers acceptable, with additional options subject to Division review and approval on a case-by-case basis.

0014-3

1724.10(f): Commenter requests clarification on whether the Division intends operators to monitor injection wells that are off-line for maintenance. In commenter’s view, any pressure monitoring of wells that are off-line (whether continuous or not) is not technically justified until the wells are returned to service.

0017-6

1724.10(f): If the Division's changes to existing monitoring requirements would require significant equipment or process changes, the Division should specify a reasonable timeline for implementation before the new requirements take effect.

Response to Comment 0002-18, 0014-1, 0014-4, 0002-2, 0014-80, 0017-5, 0014-79, 0004-10, 0012-1, 0014-2, 0014-3, and 0017-6: ACCEPTED IN PART. *The monitoring and data collection from continuous injection pressure recording will facilitate effective regulation of injection operations in terms of both incident response and compliance verification. Investigation of incidents such as surface expressions or concerns about potential groundwater contamination will benefit from continuous injection pressure data. The Division will have more a complete picture of operational practices surrounding the incident or concern allowing for higher quality diagnostics and root cause analysis. The data will also enable the Division to verify compliance with other injection reporting requirements, particularly maximum allowable surface injection pressure (MASP) requirements. To facilitate the Division rapidly flagging MASP compliance concerns, operators are required to report the highest instantaneous injection pressure for each injection well each month. The current requirement that a pressure gauge or recording device “be available at all times” does not yield useful data for such investigations and compliance checks. Instead, the current regulation only allows the Division to obtain a pressure reading at one specific point in time, and the Division must take additional steps such as making a site visit or request that the operator take a gauge reading.*

The requirements for continuous injection pressure recording, found in Section 1724.10.4, incorporate alternatives proposed that reduce the burden of compliance but are equally effective in accomplishing the regulatory goals. If the injection facilities for an injection well are configured in a manner that effectively prevents injection above the maximum allowable surface injection pressure, then the necessity for continuous injection pressure is largely addressed and the Division may waive the requirement for that well. And an operator may suspend continuous injection pressure recording for a

well while the well is disconnected from all injection lines. Although the requirement is for well-specific pressure monitoring and recording, the requirement may be satisfied by recording injection pressure from a header or manifold, if the operator demonstrates the ability to calculate well-specific injection pressures from the recorded data. Although the continuous pressure monitoring and recording requirements may be satisfied with a supervisory control and data acquisition system (commonly referred to as “SCADA”), the use of such a system is not prescribed. Any effective digital or analog recording device may be used to satisfy the continuous pressure monitoring and recording requirements.

Recognizing that for many existing injection wells new equipment will be needed to comply with these requirements, operators are afforded until April 1, 2021 to meet the new requirements. In the interim, operators are required to continue to comply with the existing requirement to ensure that an accurate, operating pressure gauge or pressure recording device is available at all times, and that injection wells are equipped for installation and operation of such gauge or device.

0003-6

1724.10(f): Clarification is needed as to what “continuously recorded” means. Once per second, once every 5 minutes, once per hour, once per day? Depending on the frequency, this statement could require all injection wells be integrated into a SCADA system or have some other standalone method of recording the injection pressure. There are significant cost and integration consequences of this language.

Response to Comment 0003-6: NOT ACCEPTED. *The requirements for continuous pressure recording are now found in Section 1724.10.4. Continuous recording means the use of a Barton Chart or other digital or analog measure that can create a continuous record, or a SCADA system that can take multiple point measurements every minute.*

0004-10

1724.10(f): This appears to overlap with idle well regulations. Once a well is idle, it should be subject to that set of regulations.

Response to Comment 0004-10: ACCEPTED IN PART. *Once a well has ceased operation for two years it will meet the definition of an “idle well” and it will also be subject to the requirements for idle wells. If approval to inject in the well is suspended, then the requirement to monitor and record injection pressure would also be suspended.*

0006-1

1724.10(f): Commenter proposes that all operators be required to test to maximum anticipated injection pressure and that all operators conduct continuous annular pressure monitoring via SCADA or similar systems starting in 2020, unless an exception is granted, in line with the requirement in the Division’s new gas storage rule. This change would enable rapid detection of almost all leaking wells and ensure that all Class II wells in the state are subject to consistent integrity testing rules. This section is a sensible location for the requirement and it ought not be a heavy additional burden since operators must already have pressure monitoring equipment at the wellhead – and likely will have a SCADA or similar system to facilitate such monitoring. Annular pressure recording devices can be routed through the same system for a more complete readout on well integrity. Commenter suggests requiring the use of SCADA or similar for monitoring all annuli and casing or tubing pressures for all UIC Class II wells by January 1, 2020, consistent with the requirement set

<p>out in the Division’s new gas storage rules at 1726.7(d). Commenter also recommends language requiring immediate action and notification to the Division in case of an anomalous pressure incident.</p>
<p>Response to Comment 0006-1: ACCEPTED IN PART. <i>While some UIC projects already operate with SCADA system, the majority do not and substantial capital investment over very large project areas would be required. Operators will only be allowed to inject up to the maximum pressure tested; thus, their maximum pressure tested becomes their maximum allowable surface injection pressure. All anomalous pressure incidents require immediate reporting to the Division. The requirements for continuous pressure monitoring have been moved to Section 1724.10.4.</i></p>
<p>0008-15 1724.10(f): Commenter supports the proposed revisions but also recommends that the Division expand the parameters that must be continuously monitored and recorded beyond just pressure to also include injection rate, volume and/or mass; temperature of the injectate; and the pressure on each annuli and annulus fluid.</p>
<p>Response to Comment 0008-15: NOT ACCEPTED. <i>Total injection volumes are already reported on a monthly basis, and where more detailed or additional information could be useful in evaluating the safety of a project or well, the Division may request additional data on a case-by-case basis. The requirements for continuous injection pressure recording are now found in Section 1724.10.4.</i></p>
<p>0018-20 1724.10(f): Given digital rather than analog data collection, Commenter suggests a minimum data collection frequency should be defined. The potential consequences of the maximum pressure are substantially different if that pressure lasts one second or all month. I suggest requiring the operator to report the minimum, 10th, 25th, median, 75th, and 90th percentile pressures in addition to the maximum pressure in order to better understand the potential consequences, such as fracturing of the formation and induced seismicity. Consider weekly reporting to better constrain when a pressure increase with potential to induce seismicity occurs.</p>
<p>Response to Comment 0018-20: NOT ACCEPTED. <i>The requirements for continuous injection pressure recording are now found in Section 1724.10.4. The recording frequency should be continuous; such as with a Barton chart or SCADA recorder. The reporting recommended by the Commenter would be too burdensome for non-SCADA users to generate. Weekly reporting is unnecessary as the Division can request the data at any time.</i></p>
<p>0007-15 1724.10(g): Add “...<u>designed injection pressure (such as pressure limited by a pump or water column)</u> ...” The maximum allowable pressure is not the same as the maximum design pressure. This section needs to recognize the design pressures as a potential limitation that is below the maximum allowable pressure.</p>
<p>Response to Comment 0007-15: ACCEPTED. <i>This requirement, now found in Section 1724.10(f) has been modified to allow equipment to meet design standards for either the maximum allowable injection pressure or the maximum pressure the equipment will be subjected to.</i></p>
<p>0006-8 1724.10(h): The proposed rule has no explicit requirements for how injection wells should be constructed other than the tubing and packer requirements in this section. The Division should incorporate by reference compliance with its well construction rule for all new wells, and for existing wells, require remediation to current well construction standards or an explanation of how current well conditions meet the Division’s performance standards for safety and environmental protection.</p>

<p>Recommended text edits reference Section 1722 and provide for exception granted by the Division for good cause.</p>
<p><i>Response to Comment 0006-8: NOT ACCEPTED. Operators remain responsible for compliance with all existing statutes and regulations, including the existing well construction requirements; a cross-reference within these regulations is not needed.</i></p>
<p>0006-9</p> <p>1724.10(h): The packer should be set adjacent to a cemented interval of within 100’ of the approved injection zone. Allowing a gap facilitates the running of integrity tools such as temperature and noise logs below the packer. Further all injection wells should have at least 500’ of cement above the injection zone, consistent with the requirement in 1722.4.</p>
<p><i>Response to Comment 0006-9: ACCEPTED IN PART. The regulation, now found in 1724.10(g), has been modified to specify that the packer isolating the injection zone must be set no more than 100 feet above the approved injection zone, and that the packer may not be set below open perforations if the packer is set within the approved zone of injection. Injection wells are subject to the requirements of the existing well construction regulations, including Section 1722.4.</i></p>
<p>0008-16</p> <p>1724.10(h): No exceptions should be made to the requirement that injection must occur through tubing set on a packer. The Division has provided no explanation or technical justification for why thermal recovery wells or any other wells should be exempt from the requirement to inject and produce through tubing. Allowing injection to occur through the casing shortens the service life of and jeopardizes the integrity of the production casing by exposing it to potentially corrosive and erosive material and stress. This practice should cease.</p>
<p>0019-30</p> <p>1724.10(h): All wells must be equipped with tubing and packer. Language allowing an exception to this rule should be deleted.</p>
<p><i>Response to Comments 0008-16 and 0019-30: NOT ACCEPTED. Existing regulations include various exemptions from the requirement that injection wells must be equipped with tubing and packer. The Division has limited the scope of these exemptions by expanding the groundwater-protection focus from freshwater to USDWs and removing the exclusion for gas storage wells. But the exemptions are otherwise unchanged by this rulemaking. Although injection through tubing and packer is preferable, it is not always technically possible for some well configurations. Some slimmer profile holes may not have space for tubing and packer and some well configurations function better without tubing and packer in place. The Division believes that the mechanical integrity testing, monitoring, and evaluation requirements of these regulations will provide a highly effective regulatory framework for injection operations, even in circumstances where injection wells are operated without the benefit of a secondary mechanical barrier.</i></p>
<p>0014-81</p> <p>1724.10(h): In certain fields, water flood utilizes both annular and tubing injection in a single casing string. In addition, most steam injectors are slim-hole injectors and are not completed with tubing and packers. The exception needs to be broadened to include additional well types. As drafted, a large number of existing steam flood, cyclic producers and water flood wells would not meet the requirement to be equipped with tubing and packer.</p>

<p>The change to "One or more strings of casing" is consistent with the language from 40 CFR 146.8(b)(3)(ii) which documents that a single string of casing is a sufficient manner in which to protect a USDW.</p>
<p><i>Response to Comment 0014-81: ACCEPTED IN PART. Existing regulations include various exemptions from the requirement that injection wells must be equipped with tubing and packer. The Division has limited the scope of these exemptions by expanding the groundwater-protection focus from freshwater to USDWs and removing the exclusion for gas storage wells. But the exemptions are otherwise unchanged by this rulemaking.</i></p>
<p>0012-2, 0014-7 1724.10(h) and 1724.10.2(a)(2) and (3): The intent of a packer is to provide isolation. Currently, the industry uses other technical equivalents to a packer that meet this intent. Steam cups are one example of an alternate mechanical means to provide isolation. Steam cups are rated to the same specifications for heat and pressure and have been effectively used for this purpose in California for decades. Isolation provided by steam cups can be demonstrated through an inert gas profile survey. Revising the draft language to allow for a technical equivalent to a packer would allow for the continued use of steam cups and also allows for the possibility of technological advances in this space leaving room for the regulations to respond to such advances without the need to revise the regulations in the future.</p>
<p><i>Response to Comments 0012-2 and 0014-7: ACCEPTED. The language of the regulation has been modified to allow for the technical equivalent of a packer, provided that the alternative will isolate the production tubing from the inside of the casing, subject to approval by the Division.</i></p>
<p>0018-60 1724.10(h): Minor edit, "...tubing and packer <u>are</u> is not required for..."</p>
<p><i>Response to Comment 0018-60: ACCEPTED. Text has been edited as recommended.</i></p>
<p>0018-21 1724.10(h)(2)(C): How does the use of tubing and packer protect high-pressure zones?</p>
<p><i>Response to Comment 0018-21: ACCEPTED. Text relating to the protection of high-pressure zones has been removed from the regulation.</i></p>
<p>0018-22 1724.10(h)(2)(C): The use of "oil" zones is redundant with "hydrocarbon" mentioned earlier in the list. Also, there may be anomalous zones that do not contain oil that are worth protecting.</p>
<p><i>Response to Comment 0018-22: ACCEPTED. "And oil" has been removed from the text.</i></p>
<p>0006-10 1724.10(i): Require Class II injection wells to be equipped with a device to automatically terminate injection if maximum pressures are exceeded to facility the requirement in this section. Such a provision is included, for example, in Ohio's Class II injection well rules (OAC1501:9-03-07(G)), and ensures that wells are not accidentally over-pressurized, which can risk the integrity of both the well and the formation.</p>
<p><i>Response to Comment 0006-10: NOT ACCEPTED. An auto-shutoff system can cause operational issues; for example, a sudden shut-off may hammer back on the pump system and cause significant damage to equipment. A slow valve-down is a better and safer way to shut down. In addition, auto-</i></p>

<p><i>shutdown usually requires SCADA or other advanced operating system which is not available to all operators.</i></p>
<p>0007-16 1724.10(j): Remove language requiring “...written approval from the Division is required to reinitiate injection...” and allow operators to resume injection at will, provided DOGGR is notified and the required testing is conducted within 30 days of resuming injection. The would be consistent with current DOGGR practices and ensures the DOGGR is notified of injection starting in an idle well, and the required tests are performed in a timely manner. Allow 90 days to submit test results to DOGGR, as 30 days more ensures reports and data is received and sent to DOGGR within the 90 days since the test.</p>
<p>0003-7 1724.10(j): Clarification needed, does this statement automatically rescind the injection permit if testing is not performed? Wells that are shut-in pending a workover repair may not be able to have such tests performed on them. For instance, an injection well that is shut-in pending packer maintenance may not be able to perform a successful RA tracer survey or SAPT test. Such a case should not be cause to rescind the approval to inject in the well.</p>
<p><i>Response to Comments 0007-16 and 0003-7: NOT ACCEPTED.</i> <i>The regulations prohibit injection in a well that is out of compliance with the mechanical testing requirements to ensure that injection only occurs in wells with demonstrated mechanical integrity. Requiring operators who do not comply with the mechanical testing requirements to halt injection into the noncompliant well is an appropriate consequence with the simultaneous benefits of motivating timely compliance and promoting safe operations.</i></p>
<p>0007-16 1724.10(j): Allow 90 days to submit test results to DOGGR, as 30 days more ensures reports and data is received and sent to DOGGR within the 90 days since the test.</p>
<p>0014-83 1724.10(j): This language has been modified to account for exceptions that are specifically identified and described in sections 1724.10.1 and 1724.10.2. These sections require the operator to shut in any well that does not demonstrate integrity. Commenter proposes deleting the language related to confinement as it is unnecessary. Commenter also strikes the requirement to provide notice to the Division within 48 hours or other period acceptable to the Division.</p>
<p><i>Response to Comments 0007-16 and 0014-83: ACCEPTED IN PART.</i> <i>The language of this section has been modified to remove the performance standard of “to ensure the injected fluid is confined to the approved zone or zones” as recommended by Commenter’s edits. The notice period of 48 hours remains, but operators have the ability to request a shorter notice subject to Division approval.</i></p>
<p>0019-31 1724.10(j): Commenter recommends removal of language allowing the Division to shorten the notice time and requiring test results submitted within 30 days instead of 60 days.</p>
<p><i>Response to Comment 0019-31: NOT ACCEPTED.</i> <i>Most of the Division’s requirements for the submission of records and test results require submission within 60 days. For consistency purposes, this clause has also been set to 60 days.</i></p>

0014-84 1724.10(k): “Related facilities” should be deleted or defined.
0014-85 1724.10(k): This section imposes open-ended monitoring and testing requirements. Any such requirements that are intended to be applicable to a particular underground injection project (e.g., requirements for casing/wellhead/safety system testing and calibration) must be set forth in the Project Approval Letter. <i>Response to Comments 0014-84 and 0014-85: ACCEPTED IN PART. This section does provide that any required monitoring would be specified in the Project Approval Letter.</i>
0002-17 1724.10(l): Commenter recommends the language be amended to specify data for cyclic steam wells should reflect total volume of fluid injected and not gallons per foot.
0004-11 1724.10(l): Commenter does not understand the requirement to retain and calculate gallons of steam per foot of injection cycles. The “foot” is not clearly defined. Also, we typically do not report in gallons in this industry. Operators provide the steam injected and DOGGR has the information about perforations and could calculate this metric if they need it. This is a burden on the operators to provide information in a form that we do not use and may require an assumption about where the steam went. Commenter would like this deleted. <i>Response to Comments 0002-17 and 0004-11: ACCEPTED. The language of the regulation has been changed to remove the specification for gallons per foot.</i>
0019-32 1724.10(l): The Division should collect and post relevant information such as this. Asking an operator to keep this information but not report it, is not appropriate. Commenter recommends a requirement for these records to be submitted “... <u>on a monthly basis for posting online.</u> ” <i>Response to Comment 0019-32: NOT ACCEPTED. This information can be useful for investigative and safety purposes, so the operator is required to maintain it, but it is only needed upon request. Because the Division does not need the data in all cases and it would involve additional document management by the operators and the Division without a clear purpose, it is not required.</i>
0018-61 1724.10(m): Add language, “...shall be specified in the Project Approval Letter and may include but shall not be limited to...” <i>Response to Comment 0018-61: NOT ACCEPTED. This section, now subdivision (l), is revised only to update the list of examples of possible additional requirements. Referencing such requirements in the Project Approval Letter may be appropriate on a case-by-case basis, but would be not necessary in all cases.</i>

1724.10.1 Mechanical Integrity Testing Part One – Casing Integrity

0002-2 1724.10.1: The proposed regulation continues to impose unnecessary testing on operators. In the case of cyclic steam operations, operations do not create significant stress on a wellbore and do not

<p>occur as frequently as other operations. In this case, requiring Mechanical Integrity Tests regardless of operational differences is unsafe and completely unnecessary.</p>
<p>0004-2 1724.10.1: For sandstone reservoir cyclic steam – in fields with USDW this testing is acceptable as long as it can be aligned and scheduled with normal routine maintenance. This requires running a packer which can be accomplished during routine maintenance. The testing schedule must be flexible or the costs more than quadruple (we can accomplish it every five years). In fields where there is no USDW to protect, cyclic MIT should not be required.</p>
<p>0004-3 1724.10.1: For sandstone reservoir continuous steam – This testing is redundant and unnecessary with the implementation of 1724.10.2 Part II. Packers have not been run in continuous steam injectors since mid-80’s due to well failures. Commenter objects to the proposed requirement. Running pressure tests puts oil field worker safety and the UIC project at risk. This proposed regulatory requirement is dangerous to oil field workers, stresses the cement casing, quenches the steam chest in the formation and causes well failure due to cooling the casing (from steam to water) 400 F to 90 F.</p>
<p>0014-21 1724.10.1(a): As a threshold matter, Commenter believes that requiring two-part MIT for all wells is unnecessary from a technical standpoint. For continuous injection wells that are subject testing at an annual frequency under 1724.10.2, any out of zone injection will be identified by that testing. Thus, completing testing under 1724.10.1 on a five-year frequency will not further inform regarding the status of injection. For example, an annual (or other allowed frequency) Inert Gas Profile survey conducted on a continuous injector under Part 2 shows where all injected fluid is going. No new or useful information is gained by the casing pressure test required under Part One following the successful completion of a Part 2 test. A casing pressure test should only be required if a well fails the tests outlined in 1724.10.2.</p>
<p>0014-91 1724.10.1(a): Steam and water flood wells should be exempt from the 5-year SAPT requirement, as temporary shut-in of injectors to perform psi testing can compromise the integrity of the casing and completion. Strict across the board requirement could also force premature abandonment of bottom part of diatomite wells depending on whether dual completion was utilized.</p>
<p>0010-4 1724.10.1 and 1724.10.2: MIT should only be required on wells with tubing and packer. All other wells would require removal of equipment and installation of a temporary packer for the sole purpose of an MIT.</p>
<p><i>Response to Comments 0002-2, 0004-2, 0004-3, 0014-21, 0014-91, and 0010-4: NOT ACCEPTED.</i> <i>Section 1724.10.1 provides specifications for the required periodic demonstration of the casing integrity of each injection well. Consistent with existing regulation, subdivision (a) requires operators to pressure test an injection well prior to commencing injection and every five years after that. But testing under this section is required more frequently – once every year – if the injection well is a gas disposal well. Gas disposal injection in a well that lacks mechanical integrity would pose significant</i></p>

health and safety risks, and therefore continual demonstrate of the integrity of such a well is necessary.

Subdivision (a) replaces the existing requirement to pressure test the “casing-tubing annulus” with a requirement to do a “pressure test of the casing.” The existing language assumed the presence of tubing and packer even though the regulations allow certain injection wells, such as cyclic steam and steamflood wells, to be completed without tubing and packer. This has resulted in confusion and inconsistent application of the testing requirement for wells without tubing and packer. Shifting the focus of the requirement to testing of the casing will make clear that all injection wells are subject to the pressure testing requirements, regardless of whether the well is equipped with tubing and packer. This is necessary because mechanical integrity is a concern with any well that will be used for class II injection operations, especially if the well does not have the secondary protection of tubing-and-packer construction.

Although testing parameters have been modified, two-part mechanical integrity testing is an existing requirement. The two parts serve different purposes – Part I MIT tests the ability of the casing to withstand anticipated pressure, while Part II MIT is designed to detect fluid migration to verify that there are no current leaks. Thus, these two tests work together to ensure ongoing mechanical integrity of a well.

Given that pressure testing is only required once every five years, operators who are concerned about temporary shut-in of injectors to perform pressure testing have the ability to schedule such testing during regular well maintenance cycles.

0014-22

1724.10.1(a): In circumstances where Part One testing is warranted, the specified five-year frequency should be determined on an equivalent basis. A cyclic steam production well that receives steam only intermittently should not be subject to the Part One MIT until it has experienced the equivalent of five years of continuous injection. Since cyclic steam producers receive only a small percentage of the steam injected into a continuous injector over the course of a year, the interval between MITs for cyclic producers should be extended accordingly. We have proposed revisions to Section 1724.10.1(a) to accomplish this result. Thus, rather than having to conduct the test every five years, the operator could extend the period between tests in consideration for the small amount of time the well is operated in injection mode. MITs are very expensive and take a well off production. Using a five-year “equivalence” standard will significantly reduce costs associated with this low-risk activity. The number of days a producing well receives steam in a given month is reflected in the data reported to DOGGR as indicated in the “Days Injecting” column in the DOGGR online well data.

Response to Comment 0014-22: NOT ACCEPTED. *Stress from injection is only one of the potential causes of compromise of a well’s integrity and if an injection well has not had a pressure test in the past five years then the integrity of that well is in question.*

0002-3	1724.10.1: Assuming the UIC program’s goal remains to protect an Underground Source of Drinking Water (USDW), testing where a USDW is not present should be substantially minimized to simply ensure well integrity for potential future abandonment.
0002-19	1724.10.1: In instances where a USDW has been shown not to be present, operators should not be required to performed pressure tests on cyclic wells. The absence of a USDW means there is no water to protect and tests aimed at ensuring this are not necessary and should not be required. Cyclic steam operations are distinctly different from other operations occurring less frequently with less stress on the wellbore and should be treated as such.
0010-3	1724.10.1 and 1724.10.2: The draft UIC regulations call for Mechanical Integrity Testing (MIT) prior to commencing injection operations (1724.10.1). They go on to require repeated MIT every 5 years with the apparent intent of demonstrating ongoing protection of drinking water. For wells that do not penetrate any underground sources of drinking water, the fluid migration check required per 1724.10.2 ensures the injection fluid is confined to the injection zone. With no underground sources of drinking water penetrated, then, there is no value / need to repeat MIT.
<i>Response to Comments 0002-3, 0002-19, and 0010-3: NOT ACCEPTED. Allowing injection at a pressure that might compromise the integrity of an injection well is inconsistent with the Division’s mandate under Public Resources Code 3106, subdivision (a), to prevent “damage to underground oil and gas deposits from infiltrating water and other causes; loss of oil, gas, or reservoir energy, and damage to underground and surface waters suitable for irrigation or domestic purposes by the infiltration of, or the addition of, detrimental substances.” Although USDW is one of the resources which must be protected, it is not the only resource. When determining the extent of the approved injection zone, the Division’s primary focus is protection of USDW, but the location of USDWs is not the only factor in determining the extent of the approved injection zone. The approved injection zone may reflect a conservative buffer around a USDW zone, there may be a need to protect groundwater that does not meet the definition of a USDW, and hydrocarbon reservoirs must be protected from infiltrating water or other detrimental substances.</i>	
0014-86	1724.10.1(a): This section lacks any reference to depth requirements. DOGGR should only be concerned with casing integrity above the permitted injection zone during MIT testing.
<i>Response to Comment 0014-86: ACCEPTED IN PART. Specification has been added in Section 1724.10.1(b)(7) that pressure tests shall test the casing of the well from the surface to a depth that is within 100 feet measured depth above the uppermost perforation, immediately above the casing shoe of the deepest cement casing, or immediately above the top of the landed liner, whichever is highest.</i>	
0008-17	1724.10.1(a): Commenter recommends that the Division restore the requirement that pressure testing is required even if the well is no longer an active injection well, unless the well is no longer approved for injection, has been plugged and abandoned, or has been converted to another purpose and is active. Idle/temporarily abandoned wells threaten the environment and human health and

<p>safety and are potential pathways for injected fluids to migrate out of the approved injection zone and should be tested on the same schedule or even more frequently than active wells.</p>
<p>Response to Comment 0008-17: ACCEPTED IN PART. <i>In order to maintain its approval to inject, a well must stay current on mechanical integrity testing as required by these regulations. A well that has become idle will be subject to the Division's idle well testing and management requirements.</i></p>
<p>0008-18</p> <p>1724.10.1(a): Commenter recommends that the Division Include more explicit requirements for actions that must be taken in the event of a failed test, specifically, require operators to: orally notify the Division as soon as practicable but no later than 24 hours following the failed test, and; perform remedial work to achieve or restore mechanical integrity. Injection may not begin or resume until a successful mechanical integrity test is performed and the results are submitted to the Division. If mechanical integrity cannot be achieved or restored, the well must be plugged and abandoned.</p>
<p>Response to Comment 0008-18: NOT ACCEPTED. <i>Operators must notify the Division prior to performing tests to provide Division staff with an opportunity to witness the tests. Regardless of whether the pressure test is witnessed by the Division, the operator is required to immediately notify the Division if the test is not successful. The primary consequence of a failed test is that the well loses the authorization to inject until the issue is remediated to the Division's satisfaction. In addition, if the Division believes that the well poses a threat to life, health, safety, or natural resources, then the Division may order the operator to undertake appropriate remedial steps.</i></p>
<p>0019-33</p> <p>1724.10.1(a): Testing should be done every year rather than every five years.</p>
<p>Response to Comment 0019-33: ACCEPTED IN PART. <i>Pressure testing injection wells at a frequency of once every five years is a requirement of existing regulation. The Division is not modifying the required frequency at this time, except with regard to gas disposal wells, which now must be pressure tested at least once every year.</i></p>
<p>0016-2</p> <p>1724.10.1(a)(3): Commenter seeks clarification on the extent of Division consultation if the liquid used for pressure testing has been previously approved and utilized in other integrity tests.</p>
<p>Response to Comment 0016-2: ANSWER. <i>Consultation is only required if the liquid to be used contains additives other than brine, corrosion inhibitors, or biocides. In such cases, liquid used for pressure testing must be approved for use in each individual well where it will be used. Different geologic and operational conditions exist at individual wells and the additives to be used must be approved each time. It is recommended that operators employing specialized additives seek multiple approvals at one time if they wish to use the same liquid in multiple wells.</i></p>
<p>0018-62</p> <p>1724.10.1(a)(4): Minor edit "...gasses..."</p>
<p>Response to Comment 0018-62: ACCEPTED. <i>The text has been edited as recommended.</i></p>
<p>0003-8</p> <p>1724.10.1(a)(5): A requirement for submission after 30 days could be confusing as it is inconsistent with 1724.10(j) that requires submission within 60 days.</p>
<p>Response to Comment 0003-8: ACCEPTED. <i>The submission requirement has been changed to 60 days.</i></p>

0014-16	1724.10.1(a)(5): The one percent gauge accuracy standard in subdivision (a)(5) is unreasonable and cannot be attained by equipment currently used in the field. It is also inconsistent with API guidance applicable to blowout prevention equipment systems for drilling wells (API S53, November 2012, Fourth Edition). Commenter recommends the one percent standard be replaced with an accuracy level based on any recognized national standard.
0014-90	1724.10.1(a)(5): Commenter recommends that the pressure gauge used for the casing pressure test be a gauge or comparable devices “that has been designed with appropriate sensitivity according to the manufacturer’s specifications” and would remove the requirement for submission to the Division to be digital.
	<i>Response to Comments 0014-16 and 0014-90: NOT ACCEPTED. Division experience in the field demonstrates that gauges of a sufficient accuracy exist and are readily available. Equivalent gauge-accuracy requirements are already in effect for underground gas storage wells under Section 1726.6.1.</i>
0018-23	1724.10.1(a)(5): Commenter suggests requiring submission of machine-readable data, otherwise digital scans of paper records may be provided.
	<i>Response to Comment 0018-23: ACCEPTED IN PART. The language has been changed to reflect a requirement for “digital” data, which should serve the same purpose as Commenter’s recommended language. A scan, which is a photo of a document would not meet this purpose unless it was digitized such that data could be read by the machine as text, not just as images.</i>
0018-63	1724.10.1(a)(5): Recommended edit, “... <u>within one percent of the maximum allowable surface pressure...</u> ”
	<i>Response to Comment 0018-63: ACCEPTED IN PART. Language was added to require accuracy within one percent of test pressure.</i>
0004-12	1724.10.1(a)(6): Commenters recommend reducing casing testing to 100 psi.
	<i>Response to Comment 0004-12: NOT ACCEPTED. In the experience of Division staff, 100 psi is too low a pressure using fluid to see a decline in the smaller volumes and to detect smaller casing holes. Thus, the minimum of 200 psi is needed to ensure that smaller defects are identified by the testing.</i>
0003-9	1724.10.1(a)(6): Maximum allowable surface pressure is defined in 1724.10.3 as MASP = (IG-IFG) * TVD). In some injection wells, MASP can be nearly 200 psi. Currently, operators may choose to test a well to a lower pressure and have that defined as the new MASP. This occurs if (a) testing the well to such a pressure may be unsafe or destructive, or (b) the maximum achievable injection pressure from injection pumps is lower than the calculated MASP. It should be clear that operators can choose to pressure test wells to a lower pressure and set that as the new MASP.
	<i>Response to Comment 0003-9: ACCEPTED. Operators may propose a lower MASP if appropriate for their operations, and an operator who tests to a lower psi than a calculated MASP will have the MASP reset to the testing pressure. Language has been modified in section 1724.10.3(a) to indicate that the</i>

MASP value for a single well “shall not exceed” the calculated MASP, allowing for a lower MASP than the calculated value.

0002-20

1724.10.1(a)(7): California state Fire Marshall Pipeline Safety requirements correctly allow for a leak rate for the test given the multitude of factors that can directly influence test results (compressibility of entrained gas, fluctuations in fluid density due to temperature changes, impact of temperature and pressure to pipeline diameter). Given the dynamics of this system, it is plausible for a pipeline test to exhibit pressure swings of 10% and still fall within the leak-off acceptance criteria. The same factors must be considered in establishing leak-off criteria for downhole well testing. As this section is written, the Division’s proposed decline rate of 2% falls within the margins of instrumentation error. Commenter recommends maintaining the 15-minute test requirements with no more than a 10% decline from initial test pressures.

0003-10

1724.10.1(a)(7): It is very difficult to achieve a 2 percent decline over a 30-minute period, even with verified casing integrity. It can often take 3-6 attempts before achieving a test that is successful by these standards. Even when carefully filling the casing-tubing annulus with fluid, there can still be trace amounts of entrained gas that need to be purged between each attempt before a successful test is achieved. At a length of one hour per test, this can require an entire day of testing. Commenter recommends thirty-minute test with fifteen-minute intervals.

0007-17

1724.10.1(a)(7): Change pressure testing parameters to 30 minutes with 5% in first 15 and 1% in second 15. This change makes the pressure test identical to the pressure test in the proposed idle well regulations. Having them the same prevents a failed pressure test due to not following the approved process.

0014-15

1724.10.1(a): It is Commenter’s understanding that the Division did not conduct a formal study to arrive at the pressure testing criteria in the proposed regulations. Commenter believes the combination of the higher test pressures and more stringent pressure bleed-off allowance required under the proposed regulations is unattainable and has no scientific basis. The requirements are also inconsistent with the industry standard, which rates a pressure test as “successful” if the pressure gauge does not show more than a 10 percent decline from the initial test pressure in the first 30 minutes. Furthermore, the Division has provided no scientific basis for either the one-hour duration of the pressure test, the full MASP requirements for this secondary containment barrier, or the 2% “bleed-off” requirement. Regulatory bodies in both Canada and the United States recognize the complexities of testing these wells and account for this complexity with both lower pressure testing and more reasonable bleed-off requirements. Our review of these standards from other jurisdictions indicates that the duration was never more than 30 minutes and the test pressure was never at MASP. In addition, the allowed bleed-off was never as low as 2%. In fact, the proposed 2% decline rate falls within the margin of instrumentation error. The 2% bleed-off requirement also appears to be inconsistent with US EPA Region 5 Guidance #5, “Determination of the Mechanical Integrity of Injection Wells” (February 2008), which provides that if annulus test pressure changes by 3% or more (gain or loss), the well has failed to demonstrate mechanical integrity pursuant to 40 CFR §

146.8(a)(1). It should be noted that US EPA Region 5's pressure change requirement is associated with a 300-psi test. The bleed-off requirements outlined by the Division at full MASP are unrealistic. For these reasons, Commenter recommends maintaining the 15-minute test requirements with no more than a 10% decline rate from initial test pressures. Additionally, Commenter believes the requirement that pressure tests be conducted at an initial test pressure "of at least the maximum allowable surface pressure" is inconsistent with the industry standard of an initial test pressure of 300 psi.

0017-8

1724.10.1 and 1724.10.2: The proposed modifications to the pressure testing requirements are significant and unreasonable. The proposed testing criteria fail to appropriately recognize the principles of fluid mechanics and thermodynamics, do not align with industry standards for the hydrostatic testing of surface pipelines and are excessive relative to all published guidelines for Class-II UIC testing. Mechanical integrity is accurately demonstrated throughout the world with the application of industry standard test criteria, and there is no justification to require operators and testing companies to deviate in the proposed UIC regulations from those criteria. DOGGR pipeline inspection guidelines reference the California State Fire Marshal Pipeline Safety and Enforcement Division requirements. These testing requirements correctly allow for a leak rate recognizing the multitude of factors that can directly influence test results (including compressibility of entrained gas, fluctuations in fluid density due to temperature changes, and impact of temperature and pressure to pipeline diameter). Given the dynamics of this system, a pipeline test is expected to exhibit pressure swings of up to 10% and meet leak off acceptance criteria. These same factors must be considered in establishing leak off criteria for down hole well testing.

In reviewing published acceptance criteria for UIC testing, in every case identified we found:

- (1) The test pressure was lower than DOGGR's proposed requirements
- (2) The duration was shorter than DOGGR's proposed requirements
- (3) The acceptable change in pressure was greater than DOGGR's proposed requirements

UIC testing requirements across the industry accurately reflect the complexities of testing these non-isothermal systems. Commenter recommends aligning the Division's test criteria with industry standards for test pressures, durations and acceptable pressure change. Importantly, the test pressure must be reduced significantly to align with industry standards. Commenter recommends 300 psi, which is the highest test pressure identified through research. Commenter recommends maintaining the test for a duration of 15 minutes with an acceptable change in pressure over the course of the test of 10%, which align with the Division's 1990 NTO governing this testing. By adopting these industry standard requirements, the Division will avoid unwarranted maintenance shutdowns of injection to investigate spurious false-positives and allow both the Division and operators to prioritize mechanical integrity resources. Those requirements have been used to successfully demonstrate integrity of UIC operations while accounting for the complexity of testing a dynamic system and do not merit change.

0014-89

1724.10.1(a)(7): Commenter recommends that the requirement in subsection (a)(7) be revised and placed in a new subdivision (c) so that it applies to pressure testing conducted under subdivision (a) or

subdivision (b). In either case, the proposed increase in the length of the pressure test to 30 minutes is unwarranted. The existing 15-minute standard with no more than 10% variance after stabilization is more reasonable standard. This test adequately demonstrates the mechanical integrity of the tested annulus. The 0.5% standard is unreasonable as any trapped gas migration or fluid temperature change could cause more than a 0.5% variation, and the pressure could go up just due to thermal expansion. Further, increasing time beyond 15 minutes introduces additional risks of thermal expansion and results may not be indicative of holes or damage. 15 minutes is consistent with NTO dated 1-9-90.

0013-9

The proposed regulations would deem “successful” a pressure test that shows as much as a 12 percent pressure loss in the first hour. The Division has not adequately explained how an observed pressure loss of that magnitude can be consistent with the existence of an effective barrier to fluid migration.

Response to Comments 0002-20, 0003-10, 0007-17, 0014-15, 0017-8, 0014-89, and 0013-9:

ACCEPTED IN PART. *The regulations as originally proposed provided a stricter standard for what constitutes a passing pressure test, which was consistent with the pressure testing parameters for gas storage wells that the Division recently adopted. Based on consideration of the relative risk profiles of gas storage wells and injection wells, as well as further consideration of various guidances on pressure testing class II injection wells, the Division determined that a shorter pressure test and a greater tolerance for pressure change is equally effective in implementing the regulatory purposes of these regulations and will be less burdensome for operators. The requirement for no more than a three-percent pressure change over a 30-minute pressure test is consistent with guidance issued by US EPA on pressure testing class II injection wells.*

Although some jurisdictions may allow operators to inject at pressure beyond what the well has been tested for, it has been the Division’s practice to require pressure testing of injection wells at the maximum allowable surface pressure, as this is necessary to confirm the well can hold the maximum pressure at which it is allowed to operate.

For wells equipped with tubing and packer, operators would have the option of performing a pressure test at lower pressures followed by ongoing annular pressure monitoring. Subdivision (c) details the process and parameters for this alternative integrity demonstration. The alternative demonstration is intended to enable operators to avoid pressurizing the well to the full maximum allowable injection pressure, provided that the well passes periodic pressure tests at lower pressure and is thereafter subject to annular pressure monitoring. Even though this alternative does not result in pressure testing at the maximum allowable pressure, it can be as good or better at detecting potential problems with the casing. Whereas a full pressure test verifies the integrity of a well at a given point in time, the alternative monitoring program would indicate potential problems on an ongoing basis. Partly for this reason, there is less of a need to require pressure testing at the maximum allowable injection pressure for wells subject to an ongoing monitoring program.

While it is necessary to demonstrate that each injection well will maintain integrity under anticipated operating pressures, pressure testing is not the only way to make that demonstration. Subdivision (d)

allows for use of alternative mechanical integrity testing instead of pressure testing, provided the alternative method is effective to demonstrate well integrity at the maximum allowable surface injection pressure. While numerous alternative mechanical integrity testing methods are less burdensome than pressure testing, not all alternatives are equally effective. Subdivision (d) provide a nonexclusive list of examples of mechanical integrity testing methods that would be as effective as pressure testing.

0018-24

1724.10.1(a)(7): These values should be different if the testing fluid if a liquid or a gas due to their differing compressibilities. Consequently, I suggest explicitly defining the pressure decline thresholds relative to the type of testing fluid. The thresholds should be based on the same theoretical volume of fluid leaking from the well over the test period.

Response to Comment 0018-24: NOT ACCEPTED. *Where the Division may approve a test using gas instead of liquid, any modification to the testing parameters that are necessary to ensure an effective integrity will be determined on a case-by-case basis.*

0018-64

1724.10.1(a)(8): Minor edit, correct a misspelling of the word “*judgement*”

Response to Comment 0018-64: ACCEPTED. *The spelling error has been corrected.*

0006-7

1724.10(f) and 1724.10.1: Annular pressure monitoring is not a substitute for pressure testing to maximum allowable surface pressure. Permitting pressure testing at only 500 psi per the alternative pressure monitoring option would not demonstrate meaningful mechanical integrity if injection is permitted above that level. Eliminating this option would simplify the Division’s integrity monitoring program while ensuring that all wells are both continuously monitored and robustly pressure tested at appropriate intervals.

0008-19

1724.10.1(b): Commenter recommends that the initial pressure test required by subsection (b)(2)(A) be the same as the pressure test required under subsection (a)(6), namely a pressure test to the maximum allowable surface pressure or 200 psi, whichever is greater.

Response to Comments 0006-7 and 0008-19: NOT ACCEPTED. *This subsection is focused on an alternative to standard pressure testing that starts with a 500-psi test and then includes continuous monitoring. The purpose of this alternative is to allow operators to maintain continuous low pressure on their wells to ensure integrity, without having to test to MASP. If the requirements for the alternative are the same as the primary test, then no meaningful alternative has been provided.*

Even though this alternative does not result in pressure testing at the maximum allowable pressure, it can be as good or better at detecting potential problems with the casing. Whereas a full pressure test verifies the integrity of a well at a given point in time, the alternative monitoring program would indicate potential problems on an ongoing basis. Partly for this reason, there is less of a need to require pressure testing at the maximum allowable injection pressure for wells subject to an ongoing monitoring program.

0018-25

1724.10.1(b)(2)(A): 500 psi is over fracture pressure for some shallow disposal wells. Commenter suggests defining the minimum testing pressure as a percentage of the fracture gradient.

0014-88

1724.10.1 (a)(6): The casing should be tested to 500 psi or the maximum allowable surface pressure, whichever is lower.

Response to Comments 0018-25 and 0014-88: NOT ACCEPTED. If the maximum allowable surface injection pressure for a well is below 500 psi, then there is no need for the operator implement the alternative pressure monitoring alternative. The operator may simply pressure test the well at the maximum allowable surface injection pressure under the parameters of 1724.10.1(b).

0002-21, 0017-7

1724.10.1(b)(2)(B)(i): Requiring the casing-tubing annulus shall have a minimum of 100 psi pressure at all times, preferably with a nitrogen blanket, is unreasonable. This proposed requirement is impractical and not necessary to ensure well competency, and this will exert unneeded pressure on older wells that could cause a loss of integrity while introducing unnecessary safety risk. Participation in the program will be limited to none given the added safety risk and operational complexity. Operators will lose the benefit of existing monitoring programs that have been installed at great expense with the Division's oversight and approval. We recommend that section this section be removed. Current approved monitoring programs implementing SCADA alarm systems with real time monitoring of casing pressures have allowed operators to successfully identify equipment failures and address them immediately. Current programs that monitor for increase in backside pressure have enabled operators to successfully identify failures and address them immediately, and the Division should continue to promote those successful programs, rather than imposing a wholesale change. However, if the Division is insistent that the backside must be measured for a drop in pressure as well, we propose the use of fluid level shots at a reasonable frequency (monthly) should suffice to evaluate for a loss of fluid in the annulus.

0014-11

1724.10.1(b)(2)(B)(i): Commenter believes the requirement to maintain a minimum annulus pressure of 100 psi, preferably through the use of a nitrogen gas blanket at the surface, is unreasonable, impractical and not necessary to ensure casing integrity. This information on annulus pressure is not gathered on wells tested to MASP for five full years between tests, and the secondary MIT test has been deemed sufficient to monitor the backside of those wells for communication. The focus on nitrogen blanketing will also discourage participation in the alternative pressure testing program, given the added safety risk and operational complexity such a requirement would introduce. Operators have made significant investment in currently approved programs, and if this provision is adopted as proposed, these operators will lose the benefit of existing monitoring programs that have been installed at great expense with the Division's oversight and approval. Additionally, current approved monitoring programs and other real-time monitoring procedures have allowed operators to successfully identify and immediately address equipment failures. Commenter thus recommends that this section be deleted, as it is unreasonable, uneconomic and would essentially bar an operator from relying on the alternative monitoring option provided by subdivision (b). Should deletion of this provision not be a feasible option, Commenter recommends the use of casing-tubing annulus fluid levels, at a reasonable frequency (i.e., monthly), as a means of evaluating potential loss of fluid.

0003-11

1724.10.1(b)(2)(B)(i): This requirement is unnecessary. Pressure variations do occur from thermal expansion; however, this can be managed by setting the alarms at reasonable thresholds that account for this. For instance, Commenter uses a SCADA system on several injectors with Hi and HiHi alarm thresholds set outside the bounds of the pressure fluctuations due to thermal expansion, but tight enough to capture any anomalous pressure event.

0014-96

1724.10.1(b)(2)(B)(i): This paragraph should be deleted altogether as it is unreasonable, uneconomic and would essentially bar an operator from relying on the alternative monitoring option provided by subdivision (b).

Response to Comments 0002-21, 0017-7, 0014-11, 0003-11, and 0014-96: NOT ACCEPTED. Positive pressure on the backside is necessary to detect small leaks, especially from the packer, which may not be detectable with fluid level tests. This alternative allows for lower pressure and lower frequency testing; the continuous monitoring is needed to ensure the alternative remains as stringent as the default requirement. Operators are not required to employ the alternative pressure monitoring option under 1724.10.1(c).

0018-65

1724.10.1(b)(2)(B)(i): Minor edit, "...pressure or other pressure in the approved plan at all..."

Response to Comment 0018-65: NOT ACCEPTED. The provision allowing for modification of the monitoring parameters appears in subdivision 1724.10.1(c)(2)(C); additional language referring to alternatives is not needed here.

1724.10.2 Mechanical Integrity Testing Part Two – Fluid Migration Behind Casing, Tubing, or Packer

0004-5

1724.10.2: For sandstone reservoir cyclic steam – Part II is unnecessary alongside Part I. Days on steam are typically a total of 15-24 days of steam injection per year. Within a cycle, the steam injected has been produced. Since most cyclic steamed wells do not use a packer, doing this test every two years will result in significant added costs for any cyclic project. Cyclic steam is less likely to go out of zone than other forms of injection because it is limited volume for a short time. A project with TOW wells can also be used to monitor for steam going out of zone. Wells that are steamed often could be tested more and wells that were seldom steamed would not have to be tested as often. If TOW wells were present in a project, then the wells around that TOW could be exempted from this testing.

0014-23

1724.10.2: This section requires MIT to be conducted in a manner that is fundamentally incompatible with the design of a cyclic steam producing well. Commenter therefore recommends that, in lieu of the Part Two test, an operator of a cyclic steam producer be allowed to provide cementing records to DOGGR demonstrating the presence of sufficient cement to prevent fluid migration behind casing. This option is expressly acknowledged in the federal UIC regulations and should similarly be allowed by DOGGR. Proposed language was crafted based on 40 CFR 146.8(c)(2). This is a critical add because all of the cyclic steam producers could not physically have the radioactive tracers, temperature logs or noise logs run.

Response to Comments 0004-5 and 0014-23: ACCEPTED IN PART. *The lack of specification in the existing regulation regarding part-two testing frequency is most significant for cyclic steam injection wells, which have come to be the most common type of injection well in the state. This lack of specificity as to frequency has led to instances of such injection wells going untested. The Division finds no science or risk-based reason to excuse cyclic steam wells from part two mechanical integrity testing. Indeed, cyclic steam wells, which periodically inject hot, highly pressurized steam, are repeatedly subject to considerable variations in temperature and pressure. These factors subject the well to stress, which makes the wells vulnerable to integrity failure. And in some areas cyclic steam operations are associated with surface expressions, which can be dangerous and environmentally hazardous. Accordingly, subdivision (b) does not specify a frequency for cyclic steam wells and cyclic steam wells are subject to the default two-year testing frequency.*

Section 1724.10.2 provides complete flexibility in selecting testing methods and protocols, provided testing will be effective to demonstrate that there is no fluid migration behind casing. Recognizing that the risk profile of cyclic steam wells can vary greatly, the Division has created a new category of “low-use cyclic steam wells” that are subject to less frequent Part II Mechanical Integrity testing.

Although testing parameters have been modified, two-part mechanical integrity testing is an existing requirement. The two parts serve different purposes – Part I MIT tests the ability of the casing to withstand anticipated pressure, while Part II MIT is designed to detect fluid migration to verify that there are no current leaks. Thus, these two tests work together to ensure ongoing mechanical integrity of a well.

0014-100

1724.10.2(a): Division approval should not be required for testing that occurs after the initial test unless a different test method is used.

Response to Comment 0014-100: NOT ACCEPTED. *The Division must approve each test but can approve a test for a batch of wells in one approval. Thus, rather than removing the requirement for notice from this subsection, operators should submit their testing approval requests in a batch, including all those wells for which a specific test will be used.*

0007-18

1724.10.2(a): The term periodically does not set a compliance schedule. Some agencies have defined periodically to every 90 days. Commenter recommends using the testing scheduled identified in this section (b)(1-5).

Response to Comment 0007-18: ACCEPTED. *The Division is in agreement, but no change is needed. Subdivision (b) and (c) address frequency of the periodic testing referred to in subdivision (a).*

0006-11

1724.10.2: There are good reasons why federal UIC rules call for a demonstration of Part II mechanical integrity prior to granting approval for the operation of a Class II well: not only does doing so establish a baseline prior to injection operations, but it allows for remediation of external mechanical failures prior to commencement of operation, that mitigating monthly of potential pollution issues. The proposed rule does not explicitly articulate that such an evaluation would occur as part of a determination of MIT Part Two compliance, however if existing cement records are

inadequate or unreliable, the Division should require a cement evaluation log prior to permitting injection.

0008-20

1724.10.2(b): Commenter recommends that the Part II MIT be performed prior to injection and then at least yearly thereafter, with no exception. The Division has provided no justification for allowing operators to inject for three months before demonstrating the well has external mechanical integrity, and this proposed provision may endanger USDWs. The Division has also provided no justification for the differing testing frequencies for different well types, other than that it is “consistent with existing regulation.” We are not aware of any scientific studies or data demonstrating that different injection well types experience mechanical integrity issues at different rates, let alone that the rates of mechanical integrity issues are consistent with the proposed testing frequencies. To the contrary, available studies of UIC wells demonstrate that determining the precise number of violations, tracking mechanical integrity and contamination incidents, and assessing their variation with time or location are not possible with existing data. Information is incomplete, outdated, or nonexistent, making it difficult to infer exact MIT failure rates or the number, extent and frequency of contamination incidents. In the absence of reliable data on the rates of mechanical integrity problems, the prudent course of action is to require MITs on a frequent and consistent schedule. We recommend that the Division restore the previous language requiring yearly Part II MIT for all injection well types.

Response to Comments 0006-11 and 0008-20: NOT ACCEPTED. The types of testing required under Section 1724.10.2 (radioactive tracer, noise log, temperature survey) must be done after injection has begun because they measure activity in the well. All three of these tests are dependent of fluid moving through the well during injection; without injection there is no noise, no significant temperature changes, no way to see tracers moving, etc. Thus, Part II MIT appropriately is scheduled for three months after injection begins when the well is operating under normal conditions.

In addition to the mechanical integrity testing requirements of Sections 1724.10.1 and 1724.10.2, a cement evaluation log may be required on a case-by-case basis under Section 1724.8 where existing cementing records are inadequate or unreliable.

0019-34

1724.10.2(b): Testing should be performed every year, with no variation for well type. Language should be added to allow the Division to “...*require more frequent testing*...”

0014-99

1724.10.2(b): Annual well testing is unnecessary; longer test frequencies are appropriate based on the type of well. Many operators have testing schedule variations that have been approved by the Division with differing time periods. Most likely, operators will be submitting those same time schedules for approval by the Division. If those time schedules are not approved by the Division, it is unlikely that enough vendor support exists in the Valley to accommodate the testing frequency outlined in this section. Commenter adds language specifying that water disposal wells shall be tested at least once each year, water flood wells once every two years, and steam flood wells once every five years.

Response to Comments 0019-34 and 0014-99: NOT ACCEPTED. The Division considered requiring Part II MIT on annual basis but determined that a default frequency of once every two years would be equally effective to achieve its regulatory purposes and substantially less burdensome for affected operators. More frequent testing may be required on a case-by-case basis if the Division identifies a need to do so.

0007-19

1724.10.2(b)(4): Many normal activities affect injection pressure greater than 15 percent such as turning on or shutting off surface injection equipment or an injection(s) well. As long as the pressure is below the fracture pressure of the formation there is no cause for fracturing the formation or pushing fluids out of the approved injection formation. From some of commenter's employees familiar with diatomite operations this requirement is appropriate and currently required for only diatomite formations. Commenter recommends that this section be deleted or noted that it applies only to the diatomite formations.

0014-19

1724.10.2(b)(4): This new requirement is written so broadly that it could apply to changes resulting from steam generation or from surface equipment upsets that have no bearing on downhole integrity. Commenter believes this requirement incorrectly links well bore integrity to pressure fluctuation, even though in many cases large pressure fluctuations are due to steam generation, rather than fluid migration. Commenter recommends that this section be revised to specify that additional testing will not be required if the unplanned variance in injection pressure is the result of steam system generation of more than fifteen percent within the twenty-four-hour period or can be attributed to known surface issues that do not directly influence downhole integrity. The regulation should clarify that variances requiring investigation should be limited to increases in injection pressure.

Response to Comments 0007-19 and 0014-19: ACCEPTED IN PART. This section sets a threshold for pressure variance as a preliminary indicator of potential problems in mechanical integrity. Language has been added to specify that additional testing will not be required if the operator can explain the variance and its cause. This section has been modified to set the trigger threshold to 25 percent rather than the original 15 percent as proposed. Based on the Division's experience with project-specific requirements, a 25 percent pressure variance is an effective threshold for flagging anomalies for investigation.

0003-12

1724.10.2(d)(1): There is no regulatory definition for maximum allowable injection rate. A maximum rate may be derived from the maximum allowable surface pressure, but it can fluctuate with changing wellbore skin, injection profile, and overall waterflood management. Running tracer surveys close to the maximum allowable surface pressure is reasonable as long as it does not interfere with the operator's waterflood management. "...should be stable and the injection pressure as close to the maximum allowable surface pressure as practical."

Response to Comment 0003-12: ACCEPTED IN PART. Some projects do have a maximum injection rate, but in this case, the Division is concerned with rate stability rather than the rate itself. Language has been modified in this section to require the "normal operating" injection rate rather than the "maximum allowable" injection rate.

0014-101
1724.10.2(d)(1): The requirement of this section should be for a stable injection rate.
<i>Response to Comment 0014-101: ACCEPTED. The word "stable" has been added to this subsection.</i>
0014-103
1724.10.2(d)(2): Vendors have stated that the casing pressure is noted and evaluated but running the test with closed casing valve does not preclude that the test results will show a broken well. May have to leverage vendor SME in order to help explain further. Opening the casing valve during steam IGP tracers presents serious safety risks.
<i>Response to Comment 0014-103: NOT ACCEPTED. If the casing-tubing annulus is not open, there might be a pressure equilibrium between the casing-tubing annulus and the injection tubing which sometimes makes it hard to detect a small tubing hole or packer leak. Also, if the casing-tubing valve is closed, there is no way to see fluid flow to the surface. Where the operator believes these parameters may result in an unsafe test, the operator should seek modification of the method from the Division in writing as provided in subsection (a).</i>
0018-29
1724.10.2(d)(5): This section seems to conflict with requirements later for the tool to be moving. Or perhaps more than one tool must be used. Or perhaps this stationary requirement is only part of the background data collection.
<i>Response to Comment 0018-29: ACCEPTED. This paragraph has been removed from the regulations.</i>
0014-104
1724.10.2(d)(11): One foot per second is arbitrary. If this criterion is used, it should be based on the casing volume where the perforations are located, not on the tubing. A 1 FPS velocity in 2-3/8" tubing is a fairly low rate (341 BWPD) and could result in a deep well with tubing to the bottom taking an unrealistically long time to log. That would result in the RA spreading quite a bit and resulting in an unreliable survey.
<i>Response Comment 0014-104: ACCEPTED. Language related to fluid velocity at one foot per second has been removed from the regulation.</i>
0018-30
1724.10.2(d)(10) and (11): These sections are incorrectly labeled as (6) and (7) in the draft text.
<i>Response to Comment 0018-30: ACCEPTED. The corrections have been made to the text.</i>
0018-31
1724.10.2(d)(11): Why beads? These would seem to be less likely to pass through well integrity defects than would a dissolved radioactive tracer.
<i>Response to Comment 0018-31: NOT ACCEPTED. The beads are just a delivery method for the radioactive tracer. They breakdown in the well and release the tracer which then works the same as the dissolved tracer. The advantage of the beads is that they dissolve and move more slowly through the well allowing for better visualization of the wellbore.</i>
0018-66
1724.10.2(d)(7): This section should include the language "excepting steam wells"
<i>Response to Comment 0018-66: ACCEPTED IN PART. Alternative testing methods for steam injection wells are indicated under subdivisions (d)(11) and (12).</i>

0018-32	1724.10.2(e)(1): Is there a scientific basis for these durations? If not, a basis could be developed through consideration of the thermal conductivity of geologic materials typical in California’s oil and gas basin, the typical temperature logging tool sensitivity, and the desired leak detection limit. Or operators could be required to calculate the necessary duration based on a defined leak detection limit.
0018-33	1724.10.2(e)(4): Is there a scientific basis for either of these approaches? In other words, what is the expected leak detection limit using either of these alternative, such as the amount of temperature decline in the first and the variation between temperature logs in wells in the second?
	<i>Response to Comments 0018-32 and 0018-33: NOT ACCEPTED. These durations are based on the knowledge and experience of Division staff, which shows that the time needed for the temperature to stabilize is more than 24 hours and less than 48. As a stabilization issue, these approaches allow for a review of heating and cooling trends using the comparisons for problem identification.</i>
0014-105	1724.10.2(e)(3): This section appears to be written for diatomite purposes and needs to be modified to cover other types of operations. Current logging speed in diatomite is 60 feet per minute; that is the maximum allowable logging speed per manufacturer's recommendations; any slower and would likely burn the tool up. The language as revised allows for different technologies to be used. Logging is not currently done at the proposed speeds. This would represent a significant process change and is cost prohibitive for non-diatomite production wells. The regulations should give DOGGR flexibility to apply requirements that are tailored to specific project areas. In general, DOGGR should not prescribe specific technologies and procedures (well shut in times, tool run rates, etc).
	<i>Response to Comment 0014-105: ACCEPTED IN PART. The language of this subsection has been modified to reduce the logging speed to no more than thirty feet per minute or a faster rate approved in advance by the Division based upon the operator’s demonstration that the faster rate will yield data of at least equivalent quality.</i>
0018-34	1724.10.2(f)(2): Given the requirement in 4(C) below do operators in practice have to measure 20-foot intervals throughout?
0018-36	1724.10.2(f)(4)(c): As water quality typically does vary from one interval to the next, this would seem to require taking noise measurements at 20-foot intervals throughout most of the USDW. If this is desired, perhaps make it a requirement. Otherwise, “significant” in this context needs to be defined to allay varying subjective interpretations resulting in inconsistency.
	<i>Response to Comments 0018-34 and 0018-36: ACCEPTED. The prescriptive protocols for noise logs have been replaced with a general performance standard that logging must include repeat sections of no less than 200 feet, preferably across intervals where anomalies are present.</i>
0018-35	1724.10.2(f)(3): Commenter recommends defining a statistical or other threshold. Otherwise this is based on subjective determination that will result in inconsistency.

0018-38
1724.10.2(g): Please provide an objective definition for “anomalies.” Also, are these the same as the anomalies requiring data collection at closer spacing, or less stringent?
<i>Response to Comments 0018-35 and 0018-38: NOT ACCEPTED. The use of the words anomalous and anomaly is consistent with the dictionary definition of a deviation from what is standard, normal, or expected. This term is deliberately broad to ensure that all potentially unusual situations are highlighted, without limitation. This provides for the greatest regulatory flexibility with discrepancy addressed through dialogue between the Division and operators.</i>
0018-37
1724.10.2(f)(6): Scale is not defined for radioactive tracer logging. Rather than doing so here, there should be a machine-readable-data submittal requirement so that users can process and plot the data at any scale they wish.
<i>Response to Comment 0018-37: ACCEPTED IN PART. The scale should be appropriate to the data being measured; operators can submit digital plots if available, but they are not required. If needed, any data submitted will be returned to the operator for correction.</i>
0016-3
1724.10.2(g): Commenter reiterates the need to defer the need for “immediate action” to the situational needs at the time of anomalous pressure determination, it may not be feasible or advisable to take “immediate” action. Commenter recommends the Division modify this proposed section to require the operator to assess any anomaly and, as appropriate and necessary, take-action “at the earliest practical time under the circumstances” in order to enable operators to, e.g., prioritize employee and public safety.
<i>Response to Comment 0016-3: NOT ACCEPTED. The operator should immediately contact the Division to report any anomalous pressure determination and implement an action plan to address the anomaly, but of course should not be reckless or haphazard in doing so.</i>
0014-102
1724.10.2(b)(2): This subsection should be deleted for lack of technical justification. [Subsection proposed in discussion draft; deleted before first official draft of regulations issued.]
<i>Response to Comment 0014-102: ACCEPTED. The requirement for an adequate pressure differential across the tubing wall has been removed from this section.</i>

1724.10.3 Maximum Allowable Surface Pressure

0004-14
1724.10.3: Commenter requests that if a cyclic project is in an area of a steam flood that the gradient for the steam flood be applied to the cyclic wells. Furthermore, due to the long history of injection into many of the reservoirs that step rate testing of cyclic producers is not necessary where historical information can be presented on the sand even if it is in another field or fault block if the geological deposition is similar. This will save large amounts of fresh water.
<i>Response to Comment 0004-14: NOT ACCEPTED. Except as provided in 1724.10.3(c), the appropriate pressure must be calculated well by well. Under subdivision (c), the maximum allowable surface</i>

injection pressure for a well may be based on an estimated baseline fracture gradient for an area if data demonstrates that the estimate will be lower than the actual fracture gradient in the area.

0006-12

1724.10.3: Commenter suggests edits, especially those related to fall-off pressure verification, that provide clarity as to how to properly conduct step rate tests that are consistent with leading industry practices and will help ensure that the proper pressure (i.e., such that does not threaten formation integrity) is selected and used.

***Response to Comment 0006-12: ACCEPTED IN PART.** Some of Commenter’s language was added, including suggested percentages for each step of the test, and a requirement for digital pressure gauges, but other suggestions are overly prescriptive.*

0008-21

1724.10.3(a): The proposal to approve injection pressures that exceed the fracture gradients presents an unacceptable risk to USDWs and we request that this provision be removed. The Division specifically notes in the Initial Statement of Reasons that injecting above the fracture gradient may be “appropriate” in diatomite formations because injecting below the fracture gradient is “impossible.” This is particularly concerning given that surface expressions are most commonly associated with cyclic steam operations in diatomite formations, and that fractures created by cyclic steam injection are documented migration pathways for surface leakage. If the Division retains this provision, which we do not recommend, then at a minimum the Division must provide much greater specificity about what data, modeling, and other information operators need to provide to demonstrate that “injected fluid will remain confined to the approved injection zone, that the higher pressure does not initiate new fractures or propagate existing fractures outside the approved injection zone, and that the higher pressure will not otherwise threaten life, health, property, and natural resources.”

0019-35

1724.10.3(a): Allowing injection above the fracture gradient is inappropriate for an injection project. If an operator wants to fracture the formation, then it must apply for a well stimulation permit under SB 4. This section, which proposes to allow injection above the fracture gradient represents moving in the wrong direction, compared to existing 1724.10, subdivision (i), which mandates that the “maximum allowable surface injection pressure shall be less than the fracture pressure.” After decades of ignoring this requirement, the Division should be enforcing the regulations, rather than carving out an exemption for oil companies who have evaded the rules. This change, unnecessarily puts groundwater at risk, by allowing reckless injection activities without oversight and regulations designed to apply to fracturing.

0019-5, 0013-1

Injection should not exceed the fracture gradient.

***Response to Comments 0008-21, 0019-35, 0019-5 and 0013-1: NOT ACCEPTED.** As discussed in the Initial Statement of Reasons, confinement of injected fluids to the approved injection zone is the core principle by which the Division, and these proposed regulations, evaluate and ensure the safe operation of underground injection projects. Although as a general rule the proposed regulations require a maximum allowable surface injection pressure less than the fracture gradient (see proposed section 1724.10.3, subdivision (a)), the proposed regulations contemplate situational approval for*

injection pressure above the fracture gradient—provided that such injection can be done consistently with the core principle of fluid confinement, and that it is necessary for hydrocarbon production. Only where the operator can demonstrate to the Division that use of a surface injection pressure above the fracture gradient will not initiate or propagate fractures outside of the approved injection zone would the Division grant approval. As noted in the Initial Statement of Reasons, the primary example for this situation is hydrocarbon-rich diatomaceous formations, for which the fracture gradient is so low that injection at any pressure effectively exceeds the fracture gradient. Based on the experience and technical expertise of its staff, the Division believes that, when conditioned on the situation-specific factual demonstrations articulated in proposed section 1724.10.3, subdivision (b), surface injection pressures above formation fracture gradient may be used safely and appropriately in underground injection projects.

The Division shares the commenters concern about surface expressions. However, where it has been determined that injection above of the fracture gradient is necessary to production and can be performed without the initiation of new fractures outside the approved injection zone, or propagation of existing fractures outside the approved injection zone, the risk of surface expressions is minimized. The Division will work with operators to ensure that this type of injection does not pose a risk to life, health, property and natural resources. These regulations include various new requirements related to surface expressions that are designed to ensure that surface expressions are treated as a violation and that appropriate containment and safety measures are taken. Requirements include mandatory shut down of injection wells in an increasing radius around the surface expression, ongoing monitoring using a tiltmeter array or a real-time pressure flow monitoring system, protocols for restriction of access to hazardous areas, training including safety measures and identification of possible hazards for field personnel, 24-hour staff onsite, daily visual inspections, and continuous monitoring of steam injection rates and pressures with mandatory reporting of unplanned variance.

0008-22

1724.10.3(a): The following must be mandatory for any projects injecting above the fracture gradient:

- Full public disclosure of all chemicals used in the injection project;
- Restrictions on the use of hazardous, toxic, or otherwise harmful chemicals;
- Comprehensive chemical analysis of injectate at least every 3 months;
- Rigorous groundwater monitoring;
- Modeling and monitoring to track the subsurface extent of induced fractures and injected fluids;
- State of the art modeling of and monitoring for surface expressions;
- Injection and production (if any) must occur only through tubing set on a packer;
- Part I & II MITs at least every 6 months;
- PAL reviews at least once per year.

Response to Comment 0008-22: NOT ACCEPTED. *The Division does not see any specific regulatory justification for the imposition of these requirements on projects exceeding the fracture gradient. Where specific issues with surface expressions have been identified, the Division is imposing rigorous*

reporting and control requirements and will work with operators to ensure that any damage to life, health, property, and natural resources is prevented to the greatest extent possible. Through project specific requirements similar to those imposed in these regulations, the Division has reduced the incidence of surface expressions in recent years. The Division anticipates that the broad applications of the requirements previously included in PALs will further reduce surface expressions.

0010-2

1724.10.3(a) While the regulations allow for approval of a Maximum Allowable Surface Pressure above the fracture gradient if needed for effective resource production (1724.10.3), the wording that the “higher pressure does not initiate new fractures or propagate existing fractures outside the approved injection zone” may be interpreted as new fractures not being permitted within the approved zone either. Thermal diatomite production requires initiating new fractures and propagating existing fractures within the producing zone. In other words, the draft wording as-is could be interpreted to conflict with the fundamental production technique. Proposed rewording of this section is “new fractures and propagation of existing fractures caused by the higher pressure remain within the approved injection zone.”

***Response to Comment 0010-2: ACCEPTED IN PART.** The language in Section 1724.10.3(b)(3) has been modified to clarify that the requirement is that the higher pressure must not propagate fractures outside the approved injection zone.*

0014-12, 0017-10

1724.10.3(a): Commenter believes that, in all cases, the MASP calculation should be adjusted for flow resistance pressure (FRP) that includes, but is not limited to, dynamic friction loss, flow constrictions, localized plugging, and skin effects, all of which have a significant impact on MASP value. The proposed regulations have been updated to allow for Division approval of a higher gradient multiplier and expressly reference “factors such as friction loss” as a key reason for this change. Given the Division’s acknowledgement of the validity of this adjustment, Commenter believes this known factor (FRP) should be accounted for in the regulatory standards for MASP calculation, rather than having to be addressed on a case-by-case basis. Consistent with the Division’s mandate to optimize resource recovery, there is no reason to exclude friction from the surface pressure analysis for any well. Not accounting for FRP as a standard in MASP calculations ignores fluid mechanics and standard engineering practices.

0014-82

1724.10.3(a): The MASP calculation must be able to be adjusted for flow resistance pressure that includes, but is not limited to, dynamic friction loss, flow constrictions, localized plugging, and skin effects, all of which have a significant impact on MASP value. In some cases it could mean the difference between an Operator’s ability to inject enough volumes to maintain voidage ratios to avoid subsidence and not being able to inject enough volumes and risk subsidence as well as poor hydrocarbon recoveries. The regulations also need to account for pressure loss on limited entry completed injectors.

***Response to Comments 0014-12, 0017-10, and 0014-82: NOT ACCEPTED.** Division staff support conservative methodologies for calculating MASP. The concern with factoring friction in the calculation is that if it is not done appropriately, then it may result in unapproved injection above fracture pressure. The Division may allow, on a well-specific basis, factors such as friction loss. If the*

Division allows friction loss to be factored into the calculation, then the friction factor shall be calculated based on the new coated tubing of the largest diameter that will be used for injection. If a single well is injecting through dual injection strings, then the friction factor of the two strings shall be calculated separately. As such, operators are encouraged to propose friction loss calculations as appropriate for their own specific circumstances, but it is not considered appropriate for default inclusion by all operators.

0014-13, 0017-11

1724.10.3(a): This section should be revised to clarify that the Division's exercise of authority to assign an "other multiplier" is intended to set the 0.95 safety factor as the lower limit. Commenter understands the purpose of this provision is to allow the Division to grant higher gradients given verification of the criteria noted. As written, however, the proposed regulation could be interpreted to provide the Division with authority to unilaterally reduce gradients.

Response to Comments 0014-13 and 0017-11: NOT ACCEPTED. *This section allows an operator to request a higher multiplier subject to Division approval. Where no request is made, no change will be initiated unless needed to prevent damage to life, health, property, and natural resources.*

0017-9

1724.10.3(a): we believe the Division's maximum allowable surface pressure (MASP) determination should not focus on a single number from a step rate test. Instead, the Division should adopt the US EPA's longstanding approach, which focuses on the confining barrier between the injection zone and an USDW. This approach prevents injection that would compromise the confining barrier and better aligns with DOGGR's duties under both federal UIC regulations and state law to protect USDWs and to maximize recovery from hydrocarbon bearing zones. The regulations should be written in manner that aligns with the EPA Title 40 federal regulations (144.28.f.6.ii) which mandate that: (A) The owner or operator shall not exceed a maximum injection pressure at the wellhead which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs; and (B) The owner or operator shall not inject at a pressure which will cause the movement of injection or formation fluids into an underground source of drinking water.

Response to Comment 0017-9: ACCEPTED IN PART. *Section 1724.10.3(a) allows an operator to use the results of a step rate test to request the MASP that is both scientifically and operationally appropriate. The section now specifies that MASP shall not exceed the amount calculated based on the step rate test, allowing operators to request a lower MASP where needed, while section 1724.10.3(b) allows for a higher MASP if it can be used for effective resource production, will remain confined to the approved zone, does not initiate or propagate fractures outside the approved zone, and will not otherwise threaten life, health, property, or natural resources.*

0008-23

1724.10.3(b): Commenter objects to the Division's proposal to allow the use of an estimated baseline fracture gradient and request that this provision be removed, and all wells be required to perform a Step Rate Test (SRT). The Division's proposal appears to conflict with an earlier directive from the Division requiring SRTs to be run in new wells and would allow the continued use of a practice identified in the 2011 Horsley Witten review as potentially endangering USDWs.

Response to Comment 0008-23: NOT ACCEPTED. Consistent with existing regulation, section 1724.10.3 allows for MASP determinations based on a conservative estimate of the fracture gradient in the area that the well is drilled, but subdivision (c) requires that such an estimate be adequately supported by representative step rate test data or other testing or geologic data. If data and analysis demonstrate that the estimate employed is below the actual fracture gradient, then use of the estimate is appropriate.

0014-71

1724.10.3(d): Commenter believes the step rate test (SRT) procedure is too prescriptive as drafted, and that it would be better to focus on the time needed to reach stable pressure rather than fixed times of 60 or 90 minutes. A minimum interval of 15 minutes is appropriate. While DOGGR may have specific experience driving the 60- and 90-minute time requirements, these specific requirements are likely to be more problematic than helpful to operators. By specifying a minimum step length of 15 minutes, it is not necessary to establish separate time intervals for lower permeability formations.

The regulations should also allow flexibility for new technologies and protocols that may yield more precise SRT results. Fracture gradient determination in the reservoir is not always appropriate for establishing injection limits. The cap rock confines injection and provides UIC compliance, not the reservoir. Flexibility is needed in that well conditions may cause the first three steps to be above the fracture gradient.

A step-rate test provides a fracture initiating pressure which includes the rock's tensile strength and near wellbore tortuosity. For establishing fracture gradient limits, Commenter would prefer to use the fracture propagating pressure and not fracture initiating pressure. This is a conservative approach that ignores the rocks tensile strength and near wellbore effects. Step rate tests are typically conducted in a cased hole, while other tests are normally conducted in open hole while drilling a well. Ideally operators should have the option to use either step-rate test or an alternative test subject to the Division's approval.

Response to Comment 0014-71: ACCEPTED IN PART. Many of commenter's text edits have been accepted and incorporated into the regulations. In addition, the section has been modified to make time step length the discretion of the operator, with recommendations rather than requirements for the appropriate step length. Suggested step pressures have also been recommended by not required. Consistent with the interests of the US EPA, the Division is concerned with fracture initiating pressure, which will always be less than fracture propagating pressure. The conservative approach is needed to ensure protection of the formation and avoid propagation of fractures outside the injection zone. Section 1724.109.3(b) allows for "other testing or geologic data" as an alternative to a step rate test to support an estimated baseline fracture gradient, provided that the Division is satisfied that the estimated baseline fracture gradient is lower than the actual fracture gradient that would be encountered.

0018-39

1724.10.3(b): Change the word "area" to "injection zone."

Response to Comment 0018-39: ACCEPTED. Text has been edited as recommended.

<p>0018-40 1724.10.3(c) and (d): The phrase “step-rate” should be hyphenated.</p>
<p><i>Response to Comment 0018-40: ACCEPTED. Text has been edited as recommended.</i></p>
<p>0003-13 1724.10.3(d)(1): Commenter has previously conducted a step-rate test where the well started at a reduced but constant rate held long enough to achieve steady-state conditions. This allowed for more meaningful steps as no one of the steps were completely dominated by wellbore fill up or wellbore storage. This is appropriate for wells with low reservoir pressure that run at higher rates. Without this exception, 2-3 steps may be dominated by wellbore fill up/storage in these wells, making the step-rate tests difficult or impossible to interpret. To capture the reservoir pressure, the well can be shut-in 48 hours prior to the test to measure a static reservoir pressure and then turned back on 24 hours prior to the test at the reduced but constant rate that keeps the well full. Commenter is available to discuss this procedure in more detail and the industry, regulatory, and academic resources we collaborated with to validate it.</p>
<p><i>Response to Comment 0003-13: NOT ACCEPTED. The protocols of Section 1724.10.3(e) require that the well be shut in until the bottom-hole pressures approximate shut-in formation pressures; this should allow the well to reach steady state condition. Suggested steps have been added to ensure that wells are tested with a sufficient number of steps to provide meaningful data outcomes. Where steps are conducted for differing lengths of time, or a step does not yield a stabilized pressure value, or if formation breakover is not clearly demonstrated, then the Division may deem the step rate test inconclusive. Where a specific process is not prescribed by regulations, operators are responsible for using good oilfield practice following industry standards.</i></p>
<p>0003-14 1724.10.3(d)(2): Step duration consistency is more important than actual step duration. Step durations are rarely long enough to reach a stabilized pressure value. Requiring each step to reach a stabilized pressure value is unnecessary and nearly impossible to achieve. To accomplish this for both low and high rates (below and above fracture gradient), step durations will have to be multiple hours or days. Even then, a stabilized pressure value may not be achieved for only one step, invalidating the entire step rate test. There are numerous academic papers that state the importance is not the step duration, but that all steps are the same duration. Commenter has done extensive research on this subject with regulators, industry experts, and academics and can elaborate if needed.</p>
<p><i>Response to Comment 0003-14: NOT ACCEPTED. Commenter is correct that consistent step duration throughout the test is a key component of a successful completion. If a step is not stabilizing in the designated time, then stable flow has not been reached and data from the test will be inconclusive. Operators should ensure that their wells have reached stability before beginning the test. A successful step-rate test includes stable flow and consistent step length.</i></p>
<p>0008-24c 1724.10.3(d): Injection rates should be controlled with a constant flow regulator that has been tested prior to use. A throttling device is not considered sufficient. Flow rates should be measured with a calibrated turbine flowmeter. Measure and record injection pressures with a gauge or recorder (for immediate test results). Record each time step and corresponding pressure. A plot of</p>

injection rates and the corresponding stabilized pressure values should be graphically represented as a constant slope straight line to a point at which the formation fracture, or “breakdown”, pressure is exceeded. The slope of this subsequent straight line should be less than that of the before-fracture straight line. If the formation fracture pressure has definitively been exceeded, as evidenced by at least two injection rate-pressure combinations greater than the breakdown pressure, the injection pump can be stopped, and the line valve closed and pressure allowed to bleed-off into the injection zone. There will occur a significant instantaneous pressure drop (Instantaneous Shut-in Pressure or ISIP), after which the pressure values will level out. This ISIP value must be read and recorded. The ISIP obtained in this manner may be considered to be the minimum pressure required to hold open a fracture in this formation at this well. Once the ISIP is obtained, the SRT is concluded. In the event that the breakdown pressure was not obtained at the maximum test injection pressure utilized, the test results may indicate that the formation is accepting fluids without fracturing.

Response to Comment 0008-24c: NOT ACCEPTED. The provisions recommended by the Commenter would be excessively prescriptive for inclusion in the regulations; operators have access to industry guidance and standards to assist them in the proper performance of these tests. Any test that is not performed in a manner consistent with industry best practices will not be accepted by the Division.

0014-72

1724.10.3(d)(6): Second-by-second recording of these parameters is unnecessary and will produce reams of data that have no real value in assessing changes in pressure. The amount of data should depend on the test method and timed steps used.

Response to Comment 0014-72: NOT ACCEPTED. The purpose of this requirement is to facilitate continuous recording so that an accurate assessment of the pressure at every step in the process can be made. Delays between measurements could mask a potential variation in pressure that would otherwise indicate a failed test.

0008-24a

1724.10.3(d)(4): Commenters are concerned that using an alternative to real time downhole pressure recording (e.g. surface pressure measurements) has the potential to introduce significant error into the calculation of fracture pressure and that the requirement to use downhole pressure gauges should not be waived.

Response to Comment 0008-24a: NOT ACCEPTED. In order for an alternative pressure recording method to be approved, it would need to be capable of effectively capturing the data necessary to demonstrate an accurate step-rate test.

0018-41

1724.10.3(d)(5): Commenter rewrites text to say “...step-rate test and ~~before~~ for one full time step...”

Response to Comment 0018-41: ACCEPTED. The text has been edited as recommended.

0008-24b

1724.10.3(d)(6): In addition to the listed data, operators should also report the type and location of the pressure gauge; type of flow meter and calibration records; plot of flow rate versus pressure data; and discussion of any anomalous data.

Response to Comment 0008-24b: NOT ACCEPTED. This information is only necessary to evaluate the uncertainties in data analysis; instead the Division will perform its own analysis using the raw data.

0008-24d

1724.10.3(d)(7): Commenter recommends that the Division increase the notice time for a step rate test to 72 hours or 3 business days, whichever is greater, to allow for adequate time to respond to notices given over weekends.

Response to Comment 0008-24d: NOT ACCEPTED. The Division has examined its staff capacities and its travel times and is confident that 24-hours' notice is sufficient for those tests that require in-person witnessing.

0004-13

1724.10.3(e): Commenter previously submitted the US EPA Step-Rate Test procedure and have again attached it to the comment letter. In a meeting in August with DOGGR, commenter requested the rationale for the duration of 60 minutes and were told it came from one of the laboratories. When asked for the study, it was understood that there was no study that pertains to oil production wells. This testing is burdensome and will use precious water resources without adding benefit.

Response to Comment 0004-13: ACCEPTED IN PART. The requirements of concern to the Commenter have been removed from the regulations. Recommendations for step length are included, but they are not required. Instead, it is up to the operator to determine the appropriate step length provided that each of the steps is conducted for the same amount of time and a stabilized pressure value is obtained within each step.

(Note: The Commenter applied this comment to section 1724.10.1(a)(7), which is about pressure tests; comment was moved here consistent with the US EPA Step-Rate test procedure that was submitted.)

1724.11 Surface Expression Prevention and Response

0008-25

1724.11: Commenter is generally supportive of the proposed provisions of this section but thinks there needs to be a much greater emphasis on site characterization and modeling, which should be continuously informed by monitoring data, and the results of which should be used to develop a site-specific plan to prevent surface expressions. Because gathering and interpreting site-specific data is crucial to preventing surface expressions, Commenter objects to the proposed use of pre-determined variance values for injection pressure and rate in subsection (b)(4) and recommends that those values be determined by each operator as part of a site-specific risk mitigation plan. That plan should include: identification of natural or production-related surface leaks; characterization of the caprock and overburden, including identification of faults and fractures; geomechanical reservoir modeling; monitoring, including pressure measurements, observation wells, and ground motion; determination of baseline values for surface uplift and subsurface changes such as pressure or temperature that are associated with leakage events at a particular field; routine analysis and interpretation of surface-uplift data, including magnitudes, locations and rates of change; integration of monitoring data with models and baseline values to determine appropriate alarms; specific, pre-defined actions to be taken in the event of a major leak. Similarly, the distance from a surface expression in which injection must cease should also be based on site-specific data. Therefore, Commenter recommends that the proposed pre-determined distances specified in subsections

<p>(b)(5), (c), (d), and (e) should be deleted and operators should be required to determine appropriate distances based on site-specific data.</p>
<p><i>Response to Comment 0008-25: NOT ACCEPTED. This section contains default requirements that the Division believes will be an effective regulatory framework for preventing and responding to surface expressions in most circumstances. Where there may be site-specific issues or considerations that would necessitate modification of these requirements, they may be addressed on a case-by-case basis by the Division. But these default distances are necessary to standardize the minimum response actions in the event of a surface expression, as explained in the Initial Statement of Reasons.</i></p>
<p>0014-106 1724.11(a): Commenter edits this subsection to say that projects shall “be operated in such a manner to mitigate the possibility of a surface expression.” A strict prohibition against surface expressions does not reflect current reality. Active surface expressions are being effectively managed. There is an inherent conflict created by prohibiting surface expressions yet allowing for management methods. The strict prohibition should be dropped in favor of language that provides for prudent management when events occur.</p>
<p><i>Response to Comment 0014-106: NOT ACCEPTED. This subsection contains a strict prohibition against surface expressions caused by injection because they are inherently unsafe. Thus, wherever a surface expression occurs it is a violation. However, even when a violation has been committed, there are still protocols to safely handle that violation. Thus, the regulations prohibit surface expressions but still require that surface expressions be managed properly if they do occur.</i></p>
<p>0007-20 1724.11(b): Commenter recommends removing the word “all” and adding language regarding study of historical issues and using recognized engineering practices. Efforts should be focused on fields with historical surface expression issues or fields with high likelihood to have surface expressions. Sandstone formations are unlikely to have surface expressions.</p>
<p><i>Response to Comment 0007-20: ACCEPTED IN PART. The language of this section has been modified to apply the requirements to all projects that have “been known” to cause a surface expression, rather than “have the potential,” focusing more on underground injection projects with historical issues.</i></p>
<p>0014-107 1724.11(b): Commenter would add language to this section indicating that the requirements apply in the absence of “specific operational requirements set forth in the Project Letter” and specifying that the Division have documented in a PAL the potential to cause a surface expression.</p>
<p><i>Response to Comment 0014-107: NOT ACCEPTED. These requirements apply to all projects that are known to cause surface expressions regardless of the content of the Project Approval Letter. Surface expressions are hazardous, and any project known to cause them must be carefully monitored to ensure public safety.</i></p>
<p>0014-108 1724.11(b)(1): Commenter requests the addition of “subsidence flyovers” as a possible way to comply with this section.</p>
<p><i>Response to Comment 0014-108: NOT ACCEPTED. This subsection contains an example of a complying technology (continuous tilt meter array) and allows for Division approval of other ground</i></p>

<p><i>monitoring systems. Thus, additional examples do not need to be added. Instead, the operator should propose an alternative to the Division for approval.</i></p>
<p>0014-109</p> <p>1724.11(b)(1): “Real time” pressure/flow monitoring systems are not defined. Some of the systems that are commonly used and have proven effective still have a delay in relaying data. Objectives can be met through utilization of SCADA in certain instances. SCADA should be referenced as an example of technology, among others, that help achieve the goals in lieu of “real-time”.</p>
<p><i>Response to Comment 0014-109: NOT ACCEPTED. Section 1724(b)(1)(A) permits operators to use a ground monitoring system approved by the Division or a real-time pressure/flow monitoring system that will give adequate warning to prevent surface expressions. It does not specify which technologies will be accepted, but as long as the technology is an approved ground monitoring system or a real-time pressure/flow monitoring system that provides adequate warning to prevent surface expressions, it will meet the requirements of section 1724(b)(1)(A).</i></p>
<p>0002-22</p> <p>1724.11(b)(2): Commenter believes 24-hour onsite staff should only apply to thermal diatomite operations given their complexity and how shallow they are. Constant in-person surveillance of other operations is unnecessary and additional measures should be deemed appropriate. These include measures such as tilt meter arrays, automatic shut-off mechanisms, and additional automated measures deployed in the field.</p>
<p>0004-15</p> <p>1724.11(b)(2): There is no rationale to have staff on site 24 hours a day to monitor an underground injection project. The requirement seems to apply and be concerned with diatomite projects which has already specified tiltmeter monitoring. This should not be applied to sandstone projects that are at low risk for a surface expression because you never approach fracturing. This monitoring may be possible on large scale projects but even in many cases there is a single night operator. The equipment can be set up so that injection on steam projects can be shut down with the generators going down on high pressure and or alarms that call out someone who will respond. If the steam stops going in the well and an operator comes out, that is the most that can be safety done in the dark. The cost of this will double the non-steam cost on many projects without benefits. If this is to be applied to a sandstone, then the project risk should be identified that warrants the monitoring, say injection at 200’ from the surface or less.</p>
<p>0014-110</p> <p>1724.11(b)(2): Commenter removes the requirement for onsite staff and instead would simply require monitoring of project operations 24-hours a day.</p>
<p><i>Response to Comments 0002-22, 0004-15, and 0014-110: NOT ACCEPTED. 24-hour onsite staff is only required for those projects that have already been demonstrated to be at risk of causing a surface expression. Because a surface expression is a significant hazard to human life, 24-hour onsite monitoring is a necessary safety precaution in these areas.</i></p>
<p>0014-111</p> <p>1724.11(b)(3): Daily visual inspections should be able to be conducted by air or ground.</p>
<p><i>Response to Comment 0014-111: ACCEPTED. The regulations do not require operators to use a specific method in performing daily visual inspections.</i></p>

<p>0004-16</p> <p>1724.11(b)(4): An unplanned change of more than 15 percent is too low of a change to warrant notification or additional testing. This can happen adding another well to be steamed in a small project. Commenter does not think it is reasonable to record notes about every pressure variance that takes place. The concerns of blowouts or high pressure can be addressed by automating a shutdown of the generator in a small project or an alarm on a producer where multiple generators feed the project. This should be at least 30 percent. Please provide clarification on expectations of tracking pressure changes.</p>
<p><i>Response to Comment 0004-16: ACCEPTED IN PART. The threshold for this variance reporting has been increased to 25 percent.</i></p>
<p>0014-112</p> <p>1724.11(b)(4): 15% over a 24-hour period is arbitrary and should be deleted. Commenter also recommends making an exception to the requirement for continuous monitoring when wells are taken off injection for maintenance. Where significant deviation or anomalous behavior is detected, the operator shall conduct a diagnostic investigation and notify the Division in writing.</p>
<p><i>Response to Comment 0014-112: ACCEPTED IN PART. The threshold for compliance with this section has been changed from 15 percent in a 24-hour period to 25 percent in a 48-hour period, allowing more flexibility for unplanned variance that can easily be explained. When there is an unplanned variance of 25 percent over 48 hours, the operator must immediately notify the Division and initiate a diagnosis of the problem. Continuous monitoring of a well may be suspended if the well is disconnected from all injection lines; operators should disconnect during maintenance or continue to monitor.</i></p>
<p>0014-5</p> <p>1724.11(b)(4): Commenter believes the proposed 12-hour time period within which operators must conduct this diagnosis is not feasible. While operators recognize the importance of immediately commencing an investigation to determine the cause of an unacceptable variance in injection pressure or rate of injection, these investigations are typically conducted pursuant to a plan developed in consultation with Division staff and can take months to complete. Accordingly, Commenter suggests that Section 1724.11(b)(4) be modified to require that a diagnosis be initiated within 12 hours.</p>
<p><i>Response to Comment 0014-5: ACCEPTED IN PART. The language of this section has been changed to require the <u>initiation</u> of a diagnosis within 12 hours rather than completion. If the diagnosis as initiated cannot provide assurances of containment within 72 hours, the immediate cessation of injection in target wells is triggered.</i></p>
<p>0014-6</p> <p>1724.11(b)(4): Continuous monitoring should not be required for inactive wells.</p>
<p><i>Response to Comment 0014-6: ACCEPTED. The language of this section has been modified to require monitoring of <u>active</u> injection wells only.</i></p>
<p>0018-42</p> <p>1724.11(b)(4): Is there a scientific basis for these values? What leak detection limit might they imply?</p>

<p>Response to Comment 0018-42: NOT ACCEPTED. <i>The Division is still gathering data on these variances as it does not have studies which show the proper thresholds. As additional data is gathered, the regulatory thresholds will be reevaluated.</i></p>
<p>0014-113 1724.11(b)(4)(A)-(D): Commenter recommends minor edits to focus on data and documentation and remove overall system operations investigatory requirements.</p>
<p>Response to Comment 0014-113: NOT ACCEPTED. <i>Commenter treats these subsections as requirements for submission to the Division focusing on the data and documentation that must be submitted; that is not the intent of this section. Instead, the subsections of (b)(4) are required steps that must be taken as part of the investigation into a reportable unplanned variance.</i></p>
<p>0002-23, 0007-21 1724.11(b)(5): Commenter recommends the language be amended to reduce the radius of 500 feet to 150 feet, which is consistent with many existing PALs. Commenter proposes a phased approach to these conditions. If the threat of steam leaving the approved injection zone exists, an operator should only be required to immediately cease injection wells that have an injection interval within 150 feet and, if unaddressed, escalate to 300 or 500 feet within 5 days of the variance occurring. An initially larger radius may unnecessarily jeopardize a project’s viability.</p>
<p>0010-6 1724.11(b)(5): Consider reducing the 500 feet “no steam zone” to 150 feet from any well suspected of casing damage (1724.11(b)(5)). That distance is more in-line with the proposed regulations which also propose a 300 feet buffer around an active surface expression. Since active surface expressions are more severe than a suspected casing damage, it stands to reason that the “no steam zone” should be greater when an actual surface expression is observed.</p>
<p>Response to Comments 0002-23, 0007-21, and 0010-6: ACCEPTED IN PART. <i>This radius has been reduced from 500 feet to 300 feet.</i></p>
<p>0018-43 1724.11(b)(5): Is there a scientific basis for this value (of 500 feet), such as 90th percentile injector spacing? If not, Commenter understands the utility of choosing a value even if it is a best guess over having no value at all.</p>
<p>Response to Comment 0018-43: NOT ACCEPTED. <i>The Division is still gathering data to determine the appropriate safe distance for this cessation of injection and will use the circumstances created by the regulation to gather additional data to inform its approach.</i></p>
<p>0014-114 1724.11(b)(5): A radial shut-in does not meet the intent of mitigating the threat of steam leaving the zone of an affected well and could cause greater safety impacts (i.e., zero ground movement mitigation is contingent on nearby operations continuing to inject.)</p>
<p>Response to Comment 0014-114: NOT ACCEPTED. <i>The radial shut-in requirement is primarily a precautionary measure. The fact that there may be a surface expression and steam is leaving the zone because of injection activity is of great concern. Not only is there a threat to the environment, there is a threat to personnel working in the area. Where ground movement is affected, the operator should work with the Division to determine the appropriate response while the investigation is taking place.</i></p>

<p>0016-4</p> <p>1724.11(c): Commenter seeks an expanded explanation on the requirements for a sub-surface injection-production mass balancing surveillance plan.</p>
<p><i>Response to Comment 0016-4: ACCEPTED IN PART. The subsurface injection-production mass balancing surveillance system required by 1724.11(b)(1)(A) manages injection and production volumes so as to maintain a stable mass within the reservoir, thereby avoiding negative side effects such as subsidence, uplift, and surface expressions. Using a tilt meter array to monitor ground levels is one example of a mass balancing surveillance plan that will meet this requirement.</i></p>
<p>0019-36</p> <p>1724.11(c): If a surface expression occurs and the Division determines that it is caused by an injection project, the PAL shall be revoked and injection into that formation by that operator shall be permanently prohibited.</p>
<p><i>Response to Comment 0019-36: NOT ACCEPTED. Depending on the circumstances of the violation, the response recommended by the commenter may be disproportionate to the violation. Where a surface expression occurs, it is a violation and the Division may decide to take action pursuant to that violation. The regulations specify steps an operator must take in response to a surface expression, and the Division will ensure the situation is resolved safely at the operator’s expense in a timely manner.</i></p>
<p>0014-115a</p> <p>1724.11(c): Commenter recommends replacing “bottom hole location” with “completion zone” and requiring Division determination of the expanded radius after five days instead of ten.</p>
<p><i>Response to Comment 0014-115a: NOT ACCEPTED. This section outlines an escalating response to a surface expression that starts with shut in of wells within 150 feet of the surface expression flowing for 24 hours, within 300 feet between 24 hours and five days of flow, within 600 feet between five and ten days of flow, and within a Division-determined radius after ten days of flow. Commenter would have the Division determine the expanded radius at an earlier point. But the distance-based shut-in provisions are necessary to standardize the minimum response actions in the event of a surface expression. This standardized shut-in requirement also informs the operator of the consequences of a surface expression upfront and will incentivize safer, more prudent injection activities to avoid shutting in wells. Furthermore, this section does not contain the phrase “bottom hole location.”</i></p>
<p>0014-115b</p> <p>1724.11(c): Commenter recommends requiring the most recently available data rather than data for the five days preceding the surface expression.</p>
<p><i>Response to Comment 0014-115b: NOT ACCEPTED. This section now requires data from the preceding 14 days and additional data if the Division requires it. This information ensures the Division is provided the information it needs to work with operators to develop appropriate responses.</i></p>
<p>0018-44</p> <p>1724.11(c) and (d): The meaning of “within 300 feet of a well’s injection interval” is unclear. Is this distance in three dimensions? In which quite a few expressions would result in the reporting of any injection wells. Is there scientific basis for this value?</p>

Response to Comment 0018-44: ACCEPTED IN PART. *The language of these two sections has been modified to clarify that the distance shall be measured from the wellhead. The Division is still gathering data to determine the appropriate safe distance for cessation of injection and will use the circumstances created by the regulation to gather additional data to inform its approach.*

0002-24

1724.11(d): Commenter recommends the language be amended to reduce the initial radius of 300 feet to 150 feet, which is consistent with many existing PALs. Commenter proposes a phased approach to these conditions. In the event of a surface expression, an operator should only be required to immediately cease injection wells that have an injection interval within 150 feet and, if unaddressed, escalate up to 600 feet after 5 days. An initially larger radius may unnecessarily jeopardize a project's viability.

0004-17

1724.11(d): Commenter believes that immediately ceasing injection should start with 150 feet and then increase up to 300 feet in five days as an escalation and to 600 feet in ten days if not stopped. 300 feet is too large of a distance for a cyclic project where surface expressions normally have taken place. The proposed distances in this section of the regulation appear to be geared toward diatomite reservoirs.

Response to Comments 0002-24 and 0004-17: ACCEPTED IN PART. *An initial step of 150 feet for 24 hours has been added to this requirement, but the Division believes that a 150-foot radius is insufficient after 24 hours. This requirement is intended to incentivize safe practices, preventing surface expressions before they happen, and to shut in wells that may be contributing to a surface expression when one occurs.*

0018-45

1724.11(d): Commenter recommends language additions specifying "new or reactivated" surface expressions that have "begun" flowing.

Response to Comment 0018-45: NOT ACCEPTED. *Whether the surface expression is new or reactivated is not pertinent; all surface expressions must be handled in the same way in order to protect human life.*

0010-5

1724.11(b)(1)(A): Injection projects that utilize a tilt array or other continuous ground monitoring system provide near real-time warning of out-of-zone injection to prevent surface expressions. Consequently, such projects should not also be required to implement a continuous pressure and rate monitoring system. These systems are not as reliable as a tilt meter array. Consider providing the option of implementing one of the systems but not require both.

Response to Comment 0010-5: ACCEPTED. *The language of the regulation has been modified to require either a continuous tilt meter array or a real-time pressure/flow monitoring system that will give adequate warning to prevent surface expressions.*

0002-25

1724.11(d)(1): Commenter requests language be added to recognize naturally occurring seeps are not captured by the requirements of this section. "...The provisions in 1724.11(d) shall not apply to any flow, movement, or release of low pressure (gravity drainage), ambient temperature fluid such as oil and water from the shallow subsurface, which is not from the zone of injection."

Response to Comment 0002-25: ACCEPTED IN PART. A new definition has been added for the term “low-energy seep” that defines it as a surface expression where the operator has demonstrated that the fluid coming to the surface is low-energy and low-temperature, is not injected fluid, and is contained and monitored in a manner that prevents damage to life, health, property, and natural resources. Where the Division concurs that a surface expression is a low-energy seep, the operator has not committed a violation of 1724.11(a) and is not subject to the requirement to shut in injection wells around the seep.

0002-26

1724.11(e): Commenter recommends clarifying this language to require proof of a surface expression before the Division orders injection to cease at any injection well. The language should require a diagnostic evaluation verifying the causal connection with a surface expression.

Response to Comment 0002-26: NOT ACCEPTED. The Division cannot wait for definitive evidence to take action to protect life, health, property, and natural resources from the dangers associated with surface expressions. Instead, where there is a significant risk that an injection well may be causing or exacerbating a surface expression, the Division must act immediately to protect health and safety.

0004-17

1724.11(e): The Division should have to use technical information and evidence based on science to cease injection wells.

0007-22

1724.11(e): Remove “to believe” from the phrase “if the Division finds reason to believe...”. The word believe can be interpreted differently. Any decision to cease an operation needs to be based on technical evidence.

Response to Comments 0004-17 and 0007-22: NOT ACCEPTED. The Division must act to prevent harm to life, health, property, and natural resources even when there is not sufficient confirming evidence to say definitively that the harm will occur. In many cases, acting on a reasonable belief, the Division must order protective actions before such evidence is available. As the data is developed, the required actions may be modified, but the Division must be able to act on a reasonable belief.

0014-116

1724.11(g): This section does not reflect the fact that steaming may be needed to isolate and identify the source of a problem. This section should be revised to reflect DOGGR’s discretion to allow testing prior to remediation if necessary to identify operational anomalies.

Response to Comment 0014-116: ACCEPTED. With the advance written approval of the Division, the regulation now permits limited injection for the purposes of identifying the cause of a surface expression.

0007-23

1724.11(h): PRC subsection 8589.7 already requires notification and states that OES is the lead agency in spills and unauthorized releases. Reporting a controlled discharge is not a spill or unauthorized release. Only uncontrolled releases should be reported to CA OES. This prevents the misuse of state resources and prevents unnecessary costs to the state and the operator.

00014-117

1724.11(h): Recommendation to add the word “initially” to clarify that multiple notifications are not required over the course of the event. Commenter also suggests referring to CEMA’s website for the telephone number, as the number may change.

Response to Comments 0007-23 and 0014-117: NOT ACCEPTED. This information was included in the regulations in consultation with the Office of Spill Prevention and Response, and the Division will defer to them on particulars of the notification requirements.

0004-18

1724.11(i): This section appears to require a professional civil engineer to sign off a project. Civil engineers may have limited or no knowledge of wellbores or the flow of fluids in a steam flood. This appears then to be provided to DOGGR who is not required to have a professional license. This may place a burden on professionals who do not have appropriate knowledge to make declarations unless they also have petroleum engineering expertise.

0007-24

1724.11(i): There is confusion as currently written. Is the PE licensed under Chapter 7 or Division 3 of the CA Business & Professions Code? Should this be Division 3 Chapter 7 Article 3? This section deals specifically with Civil Engineers. Is it the Division’s intent to limit oil field operations to Civil Engineers? Why are professional geologists or those holding a PE in Petroleum Engineering or Mining not included in the list of persons approved to evaluate and address surface expressions including that they have stopped flowing and the area is safe for reentry? Many companies trust compliance with California Title 8 requirements to their safety staff and consultants? Exempting these key people from field safety prevents use of the people most responsible and respected to provide instructions and information regarding site safety.

0014-118

1724.11(i): There is nothing in the professional engineering certification process that would make a professional engineer any more qualified to confirm that a surface expression has stopped flowing. In addition, there are a very small number of professional engineers in the state of California. It is unnecessary to wait on an evaluation by a licensed engineer. This could create safety issues by delaying the ability of otherwise qualified individuals who response to an issue.

Response to Comments 0004-18, 0007-24, and 0014-118: NOT ACCEPTED. This section references the California Business and Professions Code, which is focused on the licensing of professional engineers. It includes not just civil engineers but all licensed engineers including petroleum engineers. It is the responsibility of each licensed professional to ensure that they are appropriately licensed to perform the engineering tasks at issue in compliance with that code.

0018-46

1724.11(i): Correction to text: “Until there has been an evaluation by a professional engineer licensed under Chapter 7 of Division 3 of the California Business and Professions Code and/or the Division is satisfied...”

Response to Comment 0018-46: NOT ACCEPTED. Language regarding the Division’s satisfaction was removed from this section, making the recommended edit no longer applicable.

0014-119

1724.11(i)(1) and (2)¹: Commenter objects to having this level of specificity regarding the sign format in the regulations. If this level of detail is truly required, it should be reflected in the PALs.

Response to Comment 0014-119: ACCEPTED IN PART. *Detailed requirements for warning and danger signs have been removed. Hazard signs must now be compliant with section 3340 of Title 8 of the California Code of Regulations.*

0013-9

Cyclic steaming is an unsafe practice. It can exacerbate existing seeps and create dangerous surface expressions. Because the proposed regulations contemplate a continued and even expanded use of cyclic steaming techniques, the proposed regulations do not do enough to protect life, health, property, and natural resources.

Response to Comment 0013-9: NOT ACCEPTED. *The Division recognizes the risks posed by surface expressions, and the particular challenges associated with cyclic steam operations. The proposed regulations add new, substantial requirements geared specifically towards preventing the occurrence of surface expressions, and to safely responding to surface expressions that do occur. The Division believes the proposed regulations address the risks of surface expressions adequately and appropriately within the context of the Division’s regulatory mission.*

The proposed regulations as a whole focus on fluid confinement as the core principle of underground injection project regulation. Proposed sections 1724.11 and 1724.12 specifically address the prevention and management of surface expressions. Proposed section 1724.11, subdivision (a), articulates: “Underground injection projects shall not result in any surface expression.” The rest of proposed section 1724.11 details requirements in furtherance of that subdivision. Proposed section 1724.11, subdivision (b), lays out a suite of preventative measures required for all underground injection projects known to have caused a surface expression or that are located in diatomaceous formations generally prone to surface expressions. Proposed subdivision (b) requires operators of those projects to develop plans for monitoring and preventing surface expressions. Additionally, proposed subdivision (b) imposes specific requirements for monitoring steam injection operations and establishes a graduated, risk-based protocol for responding to observed variations in steam injection rate, leading up to mandatory precautionary shut-in of one or more wells. Proposed section 1724.11, subdivisions (c) through (k), provide additional requirements and regulatory guidance for immediate response to the occurrence of a surface expression. Proposed section 1724.12 provides more detailed direction regarding the installation and use of surface expression containment measures.

0010-1

Of concern is that in this version of the UIC regulations, production of diatomite using cyclic steam as a recovery may not be permitted. Additionally, the proposed regulations layer on monitoring, testing and reporting requirements that simply are not feasible given the configuration of some wells, and that are administratively burdensome to the Division of Oil, Gas, and Geothermal Resources itself.

Response to Comment 0010-1: NOT ACCEPTED. *The Division is unaware of any of the provisions of the regulations which would prevent production of diatomite using cyclic steam. In fact, cyclic steam wells are explicitly authorized by many provisions in the regulations, as evidenced by their inclusion*

¹ Subsection proposed in discussion draft; deleted before first official draft of regulations issued.

as a defined term, and references to cyclic steam wells in requirement sections such as tubing and packer, record retention, and mechanical integrity. The Division has not proposed any requirements that are infeasible and is confident of its ability to handle the administrative burden posed by these regulations.

1724.12 Surface Expression Containment

0007-25a

1724.12(a)(2): This section deals specifically with civil engineers. Is it the Division’s intent to limit oil field operations to civil engineers? Why are professional geologists or those holding a PE in petroleum engineering or mining not included in the list of persons approved to evaluate and address surface expressions including that they have stopped flowing and the area is safe for reentry?

***Response to Comment 0007-25: NOT ACCEPTED.** This section references the California Business and Professions Code, which is focused on the licensing of professional engineers. It includes not just civil engineers but all licensed engineers including petroleum engineers. It is the responsibility of each licensed professional to ensure that they are appropriately licensed to perform the engineering tasks at issue in compliance with the code.*

0007-25b

1724.12(a)(2): Plans to prevent a surface expression threatening a surface water or USDW should be included in the operators’ SPCC plan.

***Response to Comment 0007-25: NOT ACCEPTED.** The regulations require a surface expression monitoring and prevention plan for all underground injection projects that have been known to cause a surface expression. This plan must include a monitoring system, a map of the project area, protocols for restricting access, and training for field personnel.*

0014-120

1724.12(a)(2) and (3): Commenter would require signoff by either a geologist or an engineer, but not both. In addition, where an engineer or geologist is unavailable, the Division should be able to inspect the surface expression containment measure to confirm the functionality to its satisfaction after the Operator submits a report showing that the containment measure was constructed as designed to safely and effectively contain or collect the flow from the surface expression.

***Response to Comment 0014-120: NOT ACCEPTED.** Where a professional is asked to provide a certification based on his or her expertise, the certification must be within the scope of work allowed by their license. Thus, where existing law dictates the need for a license, the work must be conducted or signed off by the appropriately licensed professional.*

0014-121

1724.12(a)(4): Continuous monitoring is unnecessary, as is attempting to measure the rate of flow from a surface expression. Vacuum trucks are called to the site to remove the material, and these volumes of removed materials are tracked. Commenter recommends text edits to limit monitoring to visual observation with notification (but not immediate) to the Division if the surface expression “appears to significantly” increase in flow or size, reactivate or move if there is any indication that the effectiveness of the containment measure has diminished.

Response to Comment 0014-121: ACCEPTED IN PART. The term “continuously” was deleted. Operators will now be required to measure surface expression flow daily and maintain records of those measurements for as long as the surface expression persists. Operators will still be required to immediately report increases in flow. Immediate reporting of increases is necessary to provide the Division up-to-date information of the surface expression flow in order to assess how well the containment measures are working.

1724.13 Universal Operating Restrictions and Incident Response

0006-13
 1724.13: The Division’s gas storage rulemaking included sophisticated and protective emergency response planning protocols that should be imported into the rules for injection wells. This section provides that operators must stop injection and follow Division protocols should a problem arise, but more specificity and advanced planning could help save lives and protect the environment were an incident to occur. Commenter recommends adapting the emergency response provisions in section 1726.3.1 of the gas storage rule toward that end.

Response to Comment 0006-13: NOT ACCEPTED. All operators are required to have a spill contingency plan (Sections 1722, 1722.9, and 1743), which covers emergency response related to wells and well operations.

0008-26a
 1724.13(a)(3): Recommend the addition of “cement” to the list of failures that must be reported.

Response to Comment 0008-26a: ACCEPTED. Cement failure has been added to the list of failures that lead to a requirement for immediate cessation of injection in a well.

0014-122
 1724.13(a)(3) and (4): Requirement to cease injection should be limited to confirmed breaches in casing integrity that occur above the approved zone of injection.

0014-123
 1724.13(a)(6): This paragraph should be deleted. PRC 3227 is a reporting provision regarding production/injection volumes and there are already penalties in place for failure to comply with these reporting provisions (PRC 3236.5). An operator should not be required to shut in a well simply because required information has not been submitted.

Response to Comments 0014-122 and 0014-123: NOT ACCEPTED. These requirements will strengthen the Division’s oversight of injection wells and help reduce threats to life, health, property, and natural resources by halting injection into wells that are not compliant with legal requirements. Reporting and testing requirements are central to the Division’s UIC program. Under existing regulations, operators that violate those requirements sometimes continue operations until the Division issues a remedial order. The proposed section would create clear, immediate, and consequential obligations for operators to cease injection if the well is not in compliance with the specified requirements.

0014-124
 1724.13(a)(7): This paragraph should be deleted. This does not make sense as an idle well, by definition (PRC 3008), is a well that is not in use.

Response to Comment 0014-124: NOT ACCEPTED. PRC section 3008(d) defines an idle well as “any well that for a period of 24 consecutive months has not either produced oil or natural gas, produced water to be used in production stimulation, or been used for enhanced oil recovery, reservoir pressure management, or injection.” The requirement in section 1724.13(a)(8) is designed to ensure that the Division is notified before injection begins in any well that has attained idle well status, as it is not uncommon for extended period of inactivity to correspond to neglect with regard to maintenance and compliance. This section has been modified to provide that an operator may maintain approval for injection well while it is idle by communicating with the Division.

0014-125

1724.13(a)(8): An order from the Division should be required to suspend injection.

Response to Comment 0014-125: NOT ACCEPTED. Section 1724.13 specifies a list of circumstances that require operators to notify the Division and cease injection until the Division authorizes resumption. Some of the circumstances, such as a failed mechanical integrity test and indication of fluid migration outside of the approved injection zone, relate directly to the Division’s statutory mandate to protect life, health, property and natural resources. Other circumstances, such as failure to perform a mechanical integrity test within the required timeframe and failure to submit injection and production reports, are intended to impose stronger consequences for non-compliance with testing and reporting requirements. With respect to all circumstances listed in the proposed section, the Division finds that operators should be required to cease injection on their own initiative rather than wait for the Division to follow-up with such directions.

0008-26b

1724.13(a)(9): Recommend the addition of “There is any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs[.]”

Response to Comment 0008-26b: NOT ACCEPTED. The list of circumstances that appears in this section is focused on individual wells rather than the project as a whole and provides for cessation of injection in a single individual well as a consequence of those circumstances. Injection operations that are inconsistent with the conditions of approval are prohibited, and violation of a condition or malfunction of the system to cause fluid migration would be a violation of the regulations with resulting consequences as provided for in section 1724.6.

0008-26c

1724.13(b): Recommend the addition of “Public notice shall also be provided on the Division’s website and to landowners, residents, and offset operators within 1 mile of the injection project boundary.”

Response to Comment 0008-26c: NOT ACCEPTED. Incidents are reported to OES and posted on their incident website. In the event of a surface expression, section 1724.12(a)(5) requires the operator to “mark in the field all surface expression containment measures, and shall restrict access to such containment measures,” so those at immediate risk of being injured or killed by a surface expression would be notified and prevented from approaching the surface expression.

1724.14 Monitoring and Evaluation of Seismic Activity in the Vicinity of Disposal Injection

0001-1

1724.14: Seismic monitoring would be better done centrally by DOGGR than distributed among the operators. The time it would take operators to check the website every day is not a wise use of man power. One person at the state monitoring would be more efficient and the data will be of the quality and accuracy needed. Data from the companies will be idiosyncratic and suspect by the public and interest groups. Instead, DOGGR should develop a computer program to create an overlay that can combine reported quakes with known injection wells locations and generate a report of potentially related injections and quakes, which can then be investigated. This computer program could be paid for by a one-time fee that would be more cost effective for companies than individual monitoring.

0002-27

1724.14: Commenter believes requirements under this section should be removed. The monitoring and evaluation of seismic activity can and should be done by a governmental agency. Requiring at least one individual at each operator in California to perform this monitoring is unnecessary and burdensome when one agency could easily perform this monitoring instead. If the Division decides to proceed with seismic activity monitoring, Commenter requests the Division complete a study validating the need to do this.

0004-19

1724.14: This threshold of 2.7 is too low to require an immediate notification (within 24 hours) to DOGGR. Commenter recommends raising the threshold to a level of earthquake that could potentially impact an oil field and then require the operator to notify DOGGR to inform them that they have inspected and determined the facility can continue to operate. For lower magnitudes, Commenter recommends that the operator collects any events and if there are multiple incidents in a period of time, the operator engages DOGGR to determine whether a study is needed.

0010-7

1724.14: Consider removing the requirement for continuously monitor seismic activity. This puts a burden on operators to review a government web site on a daily basis, a site that may also be monitored by DOGGR. Also, earthquake reporting is not an instant process and evaluations can change outside the 24-hour window in the regulation; the USGS describes a process whereby the magnitude of an earthquake may be updated twice after the initial data release, including when time-sensitive data processing is completed and days to weeks after the event when it is reanalyzed for archive.

0017-13

1724.14: California's 60-year history of injection activities has not been associated with earthquakes primarily due to the fact that injection is generally into permeable strata. Due to California's geology and often depleted reservoirs and DOGGR's longstanding UIC regulations, Oklahoma-style high-pressure injection into tight, less permeable formations, which has been linked to earthquake activity, does not occur in California. Movement of fluids into deeper, higher pressure formations is physically not possible. Therefore, earthquakes that occur at depths below injection must be of tectonic origin, and the proposed monitoring requirements should be removed from consideration.

0014-126

1724.14: This section should be deleted in its entirety. Seismic monitoring requirements are in place for well stimulation treatments under Section 1785.1. This type of monitoring is not justified in the context of ongoing injection activities where there is no demonstrated correlation between injection activities in California and seismic activities. The inclusion of the provision unnecessarily implies that such a link has already been found.

Injection activities in California have not been associated with earthquakes because injection pressures do not exceed the fracture gradient, and because injection is generally into permeable strata. Oklahoma-style injection where earthquakes are generated is not practiced in California. Movement of fluids into deeper higher pressured formations is physically not possible. In addition, UIC controls as described in this document prevent movement of injected fluids into deeper stratigraphic zones. Therefore earthquakes that occur at depths below injection must be of tectonic origin, and should be removed from consideration. Magnitude 2.7 M is a fairly low threshold. A requirement to conduct a “causal” investigation, even if cursory, for such a low level event in unnecessary and unduly burdensome, particularly when it is evident the event happened significantly deeper than permitted injection activities.

Response to Comments 0001-1, 0002-27, 0004-19, 0010-7, 0014-126, and 0017-13: ACCEPTED IN PART. This section has been removed from the regulations. The Division is working to develop a seismic notification system and seismic data analysis project that will meet the goals of this section. Commenters and Division staff are in agreement that centralized tracking and analysis by a government-sponsored agency will be more efficient and accurate than tracking by individual operators.

0008-27a

1724.14: Commenter supports the Division’s intent to address the risk of induced seismicity associated with injection wells, but the proposed regulations are not adequate. Operators should be required to evaluate seismic risk and the potential for induced seismicity at all proposed injection projects. This should include an analysis of background seismicity, local geology including faults and tectonically active features, local and regional stress state, proposed injection operations, and nearby instances of induced seismicity. This should also include: an evaluation of the maximum magnitude of an earthquake that could be induced based on anticipated injection volume; the probability that such an earthquake may occur, based on site-specific geologic and geophysical parameters such as fault and fracture density, lithology, and minimum horizontal stress; and anticipated pore pressure as a result of fluid injection. The results of this evaluation should be provided with the permit application. The Division should require operators to develop a site-specific analysis of induced seismic risk that considers the following elements: plans for outreach and communication; criteria for damage, vibration, and noise to assess the potential impact of induced seismicity; an assessment of site-specific natural and induced seismic hazard; probabilistic and scenario risk assessments; seismic monitoring; and a mitigation plan.

Response to Comment 0008-27a: NOT ACCEPTED. The original purpose of this section of the regulations was to create a database of seismic activity that coincides with injection activity so as to inform the analysis of a possible relationship between injection and seismic activity as has been

discovered in other states. The Division has determined that it can better provide this data through centralized research and processing of seismic data and is removing this section from the regulations.

0013-5

Section 1724.14, which requires monitoring for seismic activity, falls short of protecting the state's groundwater. The proposed regulations would require reporting of seismic activity only for earthquakes of magnitude 2.7 or above, and only for a small subset of injection wells. Given California's history with earthquakes and the noted links between wastewater injection and seismicity, this Aquifer Exemption should not be approved without adequate consideration of these threats. While the section requires monitoring and reporting of seismic activity, the provisions do not address when or whether operators should cease operations while DOGGR studies the cause of the seismic activity. DOGGR's evaluation into the cause of seismic activity and well integrity have no timeline, leaving unknown how long operators will be allowed to continue injections even after significant seismic activity has been detected and reported. There is also no guidance as to what actions DOGGR should or must take once causation is established. Seismic monitoring should apply to all injection wells. Until more is known about the link between injection activity and seismic events, it is necessary to collect more data on earthquakes near injection activity and for earthquakes farther than one mile from injection. By requiring data collection on only a small subset of injection wells, DOGGR and the state are eschewing an important opportunity to further study how injections may lead to increased seismic activity.

0018-47

1724.14(a): Are there scientific bases for these values? The earthquake catalog is complete to a lower magnitude throughout California's oil and gas basins, and even events below the completeness threshold may be detected. These smaller events provide more information regarding the potential inducement of seismicity and so should be considered when they occur within the defined distance of the injection well. Commenter suggests setting the reporting threshold to at least the magnitude of completeness. For vertical distance, Commenter suggests defining events that occur within the first seal and first pressure dissipation interval above and below the injection zone. Horizontally, Commenter suggests any event occurring within the footprint of the confined injection volume as defined in the project application.

***Response to Comments 0013-5 and 0018-47: NOT ACCEPTED.** This section has been removed from the regulations. The Division is working to develop a seismic notification system and seismic data analysis project that will meet the goals of this section but that can be implemented by a government agency so the data can be considered credible by all parties.*